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Enriching New Zealand's Future

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Consultation on Improving the Financial Security Regime for Offshore Oil and Gas Installations
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PEPANZ Submission: Improving the Financial Security Regime for Offshore Oil and Gas Installations

Introduction

This document constitutes the Petroleum Exploration and Production Association of New Zealand's (PEPANZ) submission in respect of the discussion paper *Improving the Financial Security Regime for Offshore Oil and Gas Installations* ("the discussion paper"), which was released by the Ministry of Transport in December 2016.

PEPANZ represents private sector companies holding petroleum exploration and mining permits, service companies and individuals working in the industry. PEPANZ members include the operators of offshore producing fields and exploration permits.

This submission is in two main parts:

- Part 1 – Overarching Comments
- Part 2 – Responses to specific questions and issues in the discussion paper.

Summary

Key points in PEPANZ submission:

- **It is of fundamental importance that the offshore financial assurance/security requirements can be satisfied through the use of conventional international insurance policies.**
- **The quantum/level of assurance required to be provided should be in-line with identified risks, consistent with international approaches and strike a sensible balance between potential cost and likelihood of occurrence.**
- **The financial assurance requirements need to be workable, with a predictable application and low compliance costs.**

PEPANZ welcomes the opportunity to comment on the discussion paper and agrees with the need for regulatory change in the area of financial security/assurance for offshore oil and gas installations. Government must put in place a revised regime that can be met through conventional international insurance policies, or other appropriate financial security, and which requires a quantum of assurance that is in line with identified risks, consistent with international approaches and strikes a sensible balance between potential cost and likelihood of occurrence. New requirements should also reflects and integrate with the broader checks and balances (including other financial assurance requirements) within which the industry operates in New Zealand.

We consider that given the issues identified with implementing the current regime, and the lack of alignment between the requirements and the structure of the industry, there is a case to reform the legislation itself rather than limiting changes to the assurance requirements provided under maritime protection rules. At minimum, changes to provide a Maritime Rule for financial assurance for offshore oil and gas operations that aligns with international practice are required. This would allow financial assurance requirements to be met using international insurers and ensure the cost of doing business in New Zealand remains comparative and competitive.

In terms of the specific options outlined in the discussion paper, PEPANZ considers subject to the specific comments outlined in this submission that Option 1B, Options 2B or 2C and Option 3B are the appropriate ones to be progressed. It is critical that option 3B (refine the scope of financial assurance) is progressed regardless of which other options are progressed. The detail of how these options are implemented is however critical to ensuring the revised regime is effective and workable. We have provided comments on this but further engagement with the affected industry and consultation on the details of implementation will also be required to ensure this is achieved.

It is important these changes to financial assurance requirements are implemented swiftly if practicable (i.e. by mid-2017) so as to bring improved arrangements into place and provide certainty to industry at the earliest practicable opportunity.

Part 1 – Overarching comments

In Part 1 of this submission we provide overarching comments on the context to the current review and set out what an effective and workable regime for offshore financial assurance needs to include.

Whilst PEPANZ supports maintaining and updating specific arrangements for offshore financial assurance, they cannot be seen in isolation as they are only part of the regulatory picture. As noted in the discussion paper, permit holders are subject to an overarching financial capability assessment under the *Crown Minerals Act 1991* and in relation to their ability to deliver on emergency response plans and procedures for drilling and production under *Marine Protection Rule Part 131: Offshore Installations – Oil Spill Contingency Plans and Oil Pollution Prevention Certification*. The reality is that companies involved in offshore petroleum activities need to, and do have, substantial financial resources as offshore activities (exploration, development and ongoing operations) are inherently expensive.

1.1 Issues with current regulatory provisions and implementation

Current arrangements under the *Maritime Transport Act 1994* ("MTA") and *Marine Protection Rule Part 102: Certificates of Insurance* ("Part 102") are no longer fit for purpose. The required level of ~NZ$27 million is manifestly insufficient to provide assurance in the event of a major oil spill event. At the same time it is not practical for operators to use globally standard insurance policies to meet the obligations under Part 102, despite those providing substantially higher assurance levels than currently required.

The result of this is that current industry assurance arrangements exceed regulatory requirements in terms of assurance level, generally by a factor of 10 or more, but are not compatible with the regulatory requirement. Consequently industry is providing other assurance (usually parent company guarantees) to meet the regulatory requirement. This required duplication adds complexity and costs and is not what was envisaged for what is clearly designed as an insurance based regime.[1] At the new substantially higher assurance levels proposed these approaches will become unworkable and create a barrier to investment in New Zealand compared to other jurisdictions. This is a situation that needs to be resolved and we support those proposals in the discussion paper that would enable both these issues to be addressed.

Currently, there are no international conventions in place for liability obligations for offshore oil and gas installations. Whilst the underlying rationale for the regimes in relevant countries is similar the detail of the regimes vary substantially, reflecting domestic frameworks and considerations. These differences include how liability for pollution is framed, the scope of that liability (particularly the scope of potential liability to third parties) the existence and size of any limits on liability, and how and at what level upfront assurance is provided to regulators of a company, or companies, ability to meet potential liabilities.

The assurance requirements in the MTA and Part 102 applying to the shipping and offshore oil and gas industry have origins in international maritime conventions. Whist the provisions in rule 102.7 – 102.9 of Part 102 effectively apply only to the offshore petroleum sector they don't explicitly recognise the context of this sector or the other legal obligations placed on that sector in comparison with the maritime sector. As such they aren't well suited to that purpose. It is also relevant to note that the liabilities are unlimited[2], in contrast to those requirements applying in some other jurisdictions and to shipping in New Zealand.

Key issues include the fact that these provisions don't recognise that offshore petroleum activity is conducted pursuant to permits issued under the *Crown Minerals Act 1991* and that those permits are normally held by joint ventures ("JVs") with multiple parties, which are joint and severally liable for the activities undertaken (e.g. drilling operations or petroleum production). The "permit holder" is the entity for many legal obligations. In relation to this we note that comments in paragraph 12 and elsewhere in the discussion paper appear to confuse the duties and obligations of the permit operator and permit holders under the *Crown Minerals Act 1991*. It is permit holders that are most relevant to assurance and those companies generally put in place insurance covering their interests in various permits.

As well as providing an insufficient level of assurance there are number of problems with the regime provided by the current Part 26A of the MTA and Part 102:

- The scope of liability with regard to third party economic losses is not clearly defined.[3] The uncertainty and openness associated with this definition means it does not align with relevant insurance products, for example conventional policies for managing well blowouts. Specifically, relevant insurance policies will cover third party claims for damage to property (e.g. damage to vessels, fishing gear or aquaculture infrastructure) but don't cover pure economic loss claims. Beyond this issue of insurability the uncertainty around scope could in any event put a heavy reliance on the courts to establish the scope of liability in relation to economic losses, creating costs and uncertainty for all parties.

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[1] This is evidenced amongst other things by the title of Part 102, *Marine Protection Rule Part 102: Certificates of Insurance*.
[2] Refer paragraph 80 of the discussion paper.
[3] Similar overseas regimes generally provide tighter (e.g. UK and Australian) or more specific liability provisions (e.g. Norway specifically provides for fishing impacts) reducing the level of uncertainty.

- The definition of "owner" is very broad and overlapped and does not align with the legal responsibilities under the Crown Minerals Act 1991 where the permit holder rather than the permit operator (or drilling rig owner/operator) is the responsible party.
- The definition of "installation" is not tailored to how the offshore oil and gas industry is configured. Part 102 is focussed on "installations" (e.g. platforms or drilling rigs) rather than wells themselves (wells are not even mentioned) even though it is risks from wells that are the focus of assurance. Furthermore, it is unclear how a field will be treated and whether a field with, for example, multiple wells and a FPSO will have separate requirements for each, or will be together treated as one "installation" for the purposes of the regime.
- No clarity is provided regarding what sorts of events are required to be covered (e.g. slow gradual seepage releases as well as high consequence spill events), Part 102 simply states that "the contract of insurance or other financial security in respect of the regulated offshore installation provides public liability coverage of a kind and scope suitable to meet the owner's potential liability under Part XXV[4] of the Act, and is for a sum not less than…". This matters because the types of insurance products developed to respond to these different types of event differ in nature and scale.
- No certainty is provided in regard to whether conventional terms and conditions associated with insurance policies, and what level of deductible, will be acceptable. For the requirements to be workable, internationally accepted standard policy wordings and appropriate deductibles need to be acceptable to the regulator.

Our view is that given a number of these issues emanate from the MTA itself, review and reform of Part 26A of the MTA is warranted, not just changes to assurance under Part 102.

1.2 Overarching comments on proposals in the discussion paper

We agree change is required due to the inadequacies of the status quo. The three issues separately discussed in the discussion paper (assurance for well containment, level of assurance for clean-up and compensation and coverage issues with conventional insurance policies) must however be considered in integrated way as some options to certain issues are only workable in conjunction with certain solutions to other issues. Most importantly Options 2B and 2C are only practical if the scope of financial assurance is refined (e.g. Option 3B is appropriately progressed).

The focus of the financial assurance requirements need to be clear and we believe it is on providing confidence of financial resources being available in the highly unlikely event of a large oil spill. Unlike ships that often only pass briefly through New Zealand's ports, offshore petroleum producers own permanent physical assets based in New Zealand and the companies have an ongoing business presence and staff in New Zealand. Undertaking ordinary business requires systems and access to equipment and financial resources that should be sufficient to address lesser spills and seepage events. We raise this point as we have a concern that a focus on trying to ensure that an assurance instrument (e.g. insurance policy) would pay out in every possibly situation large or small (e.g. seepage events) can detract from the key purpose for this requirement, a potential case of "perfect being the enemy of good."

[4] Should be Part 26A.

1.3 Elements required for new financial assurance requirements

Whilst we have provided responses to the proposals made in the discussion paper in Part 2 of this submission, in the below box we set out for clarity the key elements that need to be provided in order to achieve an effective and workable regime for financial assurance for offshore oil and gas operations in New Zealand.

To achieve an effective regime government needs to replace the current Part 102 with requirements that:

1. Refine the scope of financial assurance required under Part 102 so that the assurance requirement can be met with conventional insurance products.
2. Outline the types of acceptable assurance that can be provided, which should include:
    a. Insurance (e.g. Operators Extra Expense (OEE) policies for wells)
    b. Self-insurance
    c. Guarantees/parent company guarantees
    d. Bonds
    e. Deposits
    f. An indemnity or other surety
    g. A letter of credit from a financial institution
    h. Other appropriate financial security accepted by Maritime New Zealand
3. Introduces a requirement to demonstrate a <u>total</u> level of financial assurance for a particular well or producing field in relation to the potential costs of well containment (where relevant) and clean-up and compensation, which includes:
    a. a prescribed cost assessment methodology for well containment (where well containment is relevant[5]) that includes the costs of drilling a relief well and deploying a capping stack (where this is a relevant technology)[6]; <u>**and**</u>

    <u>**either**</u>

    b. a fixed level of required assurance for clean-up and compensation that is sufficient to address most foreseeable credible scenarios but not so high as to impose unnecessary costs (e.g. Option 2B proposed level of NZ$300 million)

    <u>**or**</u>

    c. a clear methodology for identifying the spill scenarios representing the greatest reasonably credible costs that should be modelled and a formula to apply to the modelled results to determine the appropriate score and band and therefore the required quantum of financial assurance for clean-up and compensation.
4. Address key issues of detail such as:
    a. How the overarching requirement falling on the “owner” is split amongst the various JV parties (“permit participants”) that make up the “permit holder”, which is the appropriate party to provide financial assurance.
    b. For insurance, recognise and/or provide that:
        i. OEE policies written to standard wording are acceptable in relation to wells.[7]
        ii. The total assurance level should be able to be for all parts of liability (as refined per

[5] Addressed in our response to Question 1 in Part 2 of this submission.
[6] This aspect is explicitly addressed by the UK guidance on this topic, refer section 3.5.4 of *Guidelines to assist licensees in demonstrating Financial Responsibility to DECC for the Consent of Exploration and Appraisal Wells in the UKCS*, Issue 1 November 2012, UK Oil and Gas Association.
[7] There are at least two forms of standard Operators Extra Expense (OEE) policy wordings (e.g. a London market wording (EED 8/86) and the OIL wording (https://www.oil.bm/) and the requirements should be broad enough for permit holders to be able to utilise these or policies utilising other suitable wording.

Option 3B). This should not be required to be subdivided into compartmentalised parts as separate assurance requirements because insurance policies aren't generally subdivided in this way.[8]

iii. How determinations will be made as to the appropriate terms and conditions of that insurance, such as level of deductibles[9] on insurance policies etc. Standard policy wordings should be relied upon.

iv. The fact that a company's insurance programme will normally apply to all of an industry participant's exposures – so for companies it would not be ring-fenced to a single permit or for New Zealand activities only.

c. Where assurance is based on a customised or scaled/banded approach, provide clarity on:
   i. What scenarios should be modelled for the purposes of applying the formula to determine the scaled level.
   ii. The assumptions that should be applied to modelled scenarios.
   iii. How modelling should be undertaken, having regard to the model outputs required in the specified methodology.

d. How companies can efficiently meet their financial assurance obligations in relation to multiple permits.

Part 2 – Responses to specific questions and issues in the discussion paper

Issue 1: Financial assurance for well containment

QUESTION 1: Which is your preferred option? Why? What are the strengths and weaknesses of each option?

Whilst Option 1A (status quo) would be potentially cheaper for the industry to comply with we do not consider it appropriate. In the event of a loss of well control, well containment costs could be significant and it is logical for financial assurance to be provided in relation to this. Whilst, as noted in Paragraph 20 of the discussion paper, under Maritime Rules Part 131 Maritime New Zealand assesses whether applicants have sufficient financial resources available to give effect to their emergency response plans and procedures in the event of an oil spill, we can see merit in explicitly requiring assurance for this under Part 102. Should this be progressed, as envisaged in Option 1B, it would be appropriate to integrate, streamline or remove that requirement under Part 131 to avoid any regulatory duplication.

PEPANZ supports Option 1B (Introduce a prescribed cost of financial assurance for well containment). Requiring financial assurance in relation to the possible costs of well containment is logical where uncontrolled well flow is a risk and doing so would be broadly consistent with international practice.

It is only logical however that an assurance requirement related to well control is applied to situations where the wells pose a risk of uncontrolled flow (i.e. a blowout). The analysis and

[8] The limit will generally apply across all exposures and is not per exposure, meaning the whole limit, not just part of it, is available to meet costs for any exposure.

[9] For instance, acceptable levels of deductible (e.g. up to $US20 million) need to be allowed for as these are commonly and appropriately part of insurance policies. Whilst such a deductible would equal the current assurance requirement, rendering it largely meaningless, for a material company with a policy limit of many hundreds of millions of dollars a deductible of that size million is logical and appropriate.

proposals in the discussion paper are centred on new wells being drilled rather than the risks from producing wells, which for various reasons are generally lower[10].

Some current producing offshore oil wells only flow due to artificial lift (e.g. downhole pumps) and were these to be turned off the wells do not have the pressure to flow unaided. Where a producing facility only has such wells there is no realistic risk of uncontrolled flow from wells and so requiring assurance in relation to this would be redundant and therefore inappropriate.

QUESTION 2: What are your thoughts on the proposed formulas under option 1B?

We consider the formula outlined second in the discussion paper will be most relevant to the larger number of wells and should therefore be implemented. Either formula is likely to provide a broadly representative value for new wells drilled by MODUs[11] (e.g. exploration wells or new subsea development wells). For existing wells (i.e. those already in production) which make up the majority of current offshore wells, and for wells drilled from existing platforms the estimated cost of drilling is not necessarily a useful starting point. This is because the well may have been drilled some time ago and/or it have been drilled in a manner likely to differ substantially from a relief well[12], which is what the assurance is effectively for. In either of these cases the differences render costs extrapolations from initial well cost a suboptimal approach.

Given the limitations of the first method, the second method outlined below paragraph 41 of the discussion paper ("Cost of well control = (Estimated daily rig cost x time to achieve well kill) + Cost of capping stack") is preferable as it can be applied effectively to all situations. Implementing a single method would increase certainty and reduces compliance costs.

There are a range of key matters that must be addressed to ensure application of the proposed method is appropriate and certain:

- The costs of deploying a capping stack should only be included in determining well containment costs where that is valid response option, which is where there could be a blowout from a subsea well.[13] Capping stacks are not relevant to wells where the wellhead is located on a fixed platform. This is an important distinction because of New Zealand's five offshore producing fields only one has subsea wells.
- Detail needs to be provided on how to apply the cost calculation method, including how to calculate "daily rig cost" or "cost of capping stack". We note these matters of detail are clearly addressed on pages 6 and 7 of the Australian guidance on this topic (*Method to assist*

[10] These reasons include the fitting of permanent production equipment and control systems, downhole safety valves, greater understanding of reservoir pressures and conditions and in many cases a reduction in pressure over a well's producing life. Statistics outlining relative risks are included in the following report *European Commission, Commission Staff Working Paper, Impact Assessment, Annex I, Accompanying the document, Proposal for a Regulation of the European Parliament and of the Council on safety of offshore oil and gas prospection, exploration and production activities, October 2011*.

[11] Mobile Offshore Drilling Units, which include jack-ups, semi-submersibles and drillships.

[12] For example the relevant producing well may have been drilled 10 years ago from a rig mounted on the fixed producing platform, whereas a relief well would be drilled by a MODU from a location nearby to the platform.

[13] A subsea well is a well in which all the production systems are located on the seabed. Most exploration wells will be subsea wells.

titleholders in estimating appropriate levels of financial assurance for pollution incidents arising from petroleum activities, APPEA, December 2014)[14].

- As mentioned above, some producing offshore oil wells only flow due to artificial lift (e.g. downhole pumps) and, if these were turned off or rendered inoperative, the wells do not have the pressure to flow unaided. Producing fields with only such wells should not be subject to the formula or the requirement to provide assurance for well containment as uncontrolled flow is not realistically possible.

Issue 2: Level of financial assurance for clean-up and compensation

QUESTION 3: Which is your preferred option? Why? What are the strengths and weaknesses of each option?

We do not support the continuation of the status quo (Option 2A). It provides little value in terms of assurance, as the level is materially insufficient to address a major oil release event, whilst also imposing costs and complexity on industry, because industry has to craft boutique assurance mechanisms to satisfy the regulatory obligation as conventional insurance products with higher than currently required values designed for this cannot be used to satisfy it.

Option 2B would, if appropriately introduced in conjunction with Option 3B, provide a major improvement on the status quo. The level of assurance required would be certain and sufficient to address most identified scenarios, including as identified in the discussion paper the risks associated with current producing fields. It would also be more straightforward and less costly (e.g. no new modelling required) to implement and apply than Option 2C, which would in contrast require a complex, costly and ongoing administrative process for both industry participants and the regulator.

The approach as envisaged in Option 2C of attempting to scale the assurance level required to the risk from a specific well or facility is generally logical. It does however create uncertainty (because assurance levels vary markedly and aren't necessarily apparent until modelling is undertaken) and would impose costs in terms of requiring modelling that might not otherwise be required and additional assessment time from the regulator.

The question is whether the advantages of Option 2C over Option 2B outweigh the costs and complexity it would entail. These costs are not identified or assessed in the discussion paper but it is critical these are considered carefully as part of any Regulatory Impact Statement (RIS). PEPANZ's ability to provide estimates of relative costs is limited at this stage due to the absence of key details on how the various options would be implemented and how this would relate to existing industry arrangements. More specific comments on these two options are outlined in our responses to Questions 4 to 7 below.

QUESTION 4: What are your thoughts on an appropriate financial assurance level under option 2B?

It is unclear from the discussion document whether the proposed figure of NZ$300 million for Option 3B would include well containment costs or whether those would be added to it in order to

[14] Available from https://www.nopsema.gov.au/environmental-management/assessment-process/financial-assurance/

derive a total level of assurance. We assume the latter although paragraph 56 of the discussion paper appears to suggest the former.

Adding well containment costs where relevant (as per Option 1B) would mean a total level of required assurance in the range of NZ$300-500 million in practice under this approach.[15] Given that the earlier 2014 consultation[16] on this issue proposed NZ$300 million as a total figure this option would represent a further increase of up to 50% in potentially required assurance.

We agree with the analysis in paragraph 57 of the discussion paper that a level of financial assurance of NZ$300 million for clean-up and compensation would be appropriate for most foreseeable situations (i.e. all existing producing fields and two of the three modelled scenarios for exploration wells). We also agree as stated in paragraph 59 that a fixed level of NZ$300 million for this element could exceed the potential costs of spills from some facilities/wells and equally be below that of spills from others. It does however represent a reasonable and pragmatic approach that would be appropriate for the majority of identified situations and provide lower compliance and administration costs for industry participants and the regulator.

A fixed total assurance level of NZ$300 million would be unlikely to impose additional costs on industry participants as conventional insurance levels exceed this, however, levels of NZ$400 million or greater (as could be required if well containment costs are additional) may require some participants to increase their coverage, thereby incurring greater insurance costs.[17] This could impact on the ability of some companies to participate in permits.

QUESTION 5: What are your thoughts on the draft formula under option 2C?

The banded framework proposed under Option 2C would be broadly similar to approaches in overseas jurisdictions such as Australia and the United Kingdom, although both the detail and the bands differ. The formula is based on models and we note that some of the scenarios applied go beyond conditions that have been experienced in New Zealand. We understand from the discussion paper that one of scenarios drives the higher bands in the proposed approach.

Combined with potential well containment costs proposed under Option 1B, Option 2C would give total levels of required assurance ranging from low levels to NZ$1.06 billion (~US$775 million) or beyond.[18] This is a substantial quantum and approximately 40 times higher than the current level in Part 102. To reiterate, as outlined elsewhere in this submission meeting assurance up to this sort of level requires industry specific insurance products (e.g. OEE) and so it is critical the scope of financial assurance is refined to facilitate this (i.e. Option 3B is progressed). If this does not transpire then the assurance regime would be fundamentally out of step with international norms and would likely have a major adverse effect on investment in the upstream sector in New Zealand.

[15] The range would vary on whether provision for well containment was required, and if so to what extent.
[16] *Increasing the minimum financial assurance requirement for offshore installations*, Ministry of Transport, May 2014.
[17] These comments are predicated on Option 3B being progressed.
[18] A total of NZ$1.06 billion is based on adding the highest band (Band 7 – NZ$800 million) to a possible application for the first method (for simplicity) under Option 1B for a $NZ100 million dollar well (2 x estimated NZ$100 million well cost + NZ$60 million for capping stack deployment), which gives a well containment calculation of NZ$260 million. Whilst an estimated well cost of $NZ100 million would be high, greater estimated well costs than this are also possible.

As outlined in the discussion paper the upper bands in Option 3C are high by international standards. To meet them industry participants, including international participants, may have to put in place higher limits for operations in New Zealand, which would entail extra costs and complexity. It is not possible to estimate the likely cost impact of this proposal because its impact depends on the difference between what it would require and the assurance/insurance already held by the relevant companies, which would only be apparent following a specific modelling exercise. The costs of extra insurance could however be hundreds of thousands of dollars per well, or per facility per annum. This could impact the potential of some companies to participate in the industry in some parts of New Zealand.

The extent to which New Zealand's regime diverges from international norms would be a point of potential competitive disadvantage in terms of investment. It is also critical to understand that whilst some jurisdictions (e.g. UK) have high levels of required assurance, those jurisdictions have a more refined (and insurable) scope of financial assurance <u>and</u> allow larger companies with substantial financial resources to use other mechanisms including self-insurance. These features both make it possible to, and potentially reduce the costs of, meeting the obligation.

It appears the upper bands of the proposed framework would be insurable at this time but this cannot be taken for granted into the future as insurance markets are dynamic and this level of quantum is approaching the limits of what is insurable. Our understanding is that relevant insurance, for example OEE for wells, can be secured with substantial limits (up to US$750m/~NZ$1 billion) from commercial insurance markets but the ability to do this would be subject to the ability to access specialist international insurance markets.

The availability of limits in the order of US$750 million is based on current insurance market conditions and it is possible that capacity will diminish in the future. We understand for example there was a time within the last decade when US$400 million of OEE cover was the most that was available. Whilst the limits have increased significantly in the last 3-5 years it is possible they could go down again if the dynamics of the insurance market change, which could make it impractical to comply with the higher bands in Option 3C.[19] Should this happen it could have major effects on the ability for domestic players to meet the assurance requirements. It is also important to be mindful of aggregation of risk potentially limiting available capacity, making it particularly important there is access to the international insurance markets that specialise in providing this sort of insurance.

We have the following specific comments and observations on the proposed scaled framework outlined in the box below paragraph 63 of the discussion paper:

- We understand the banding framework is based primarily on the modelling of three hypothetical extreme well blowout scenarios, although it would be applied to other spill events.[20] The discussion paper and supporting documentation is clear that a conservative approach has been taken to quantifying the likely costs of damage and control and clean up. This means that the quantum of financial assurance being sought is for an extreme (highly unlikely) modelled oil release and the resulting worst case length of coastline impacted and conservative estimates of third party activities potentially affected.

[19] Such dynamics could be impacted by offshore industry specific factors or by completely unrelated matters with the wider insurance industry or global business environment.
[20] Extreme in the sense that uncontrolled well flow would take place for over 100 days with no interventions, including capping, having any effect. Blowouts from offshore wells are highly unlikely events and when they do occur they are often resolved swiftly (i.e. within hours or a few days) by ordinary well control measures or for example through interventions on the blow-out preventers.

- The proposed banding framework results in abrupt transitions/increases in the required quantum of assurance that are disproportionate to what is justified. For instance moving from a score of 7 to 8 points increases required assurance by NZ$150 million, representing a 50% increase in required assurance as a consequence of ~15% increase in modelled impact. These steps are larger than in the equivalent Australian framework, which generally moves in A$50 million increments.
- The rationale for requiring up to NZ$50 million in assurance (Band 1) for clean-up and compensation for when no shoreline impact is anticipated is not clearly outlined in the discussion paper and is not apparent given that the cost for the lowest assessed scenario was NZ$12million and that involved a small amount of oil on shore.

In implementing a banded system such as Option C it would be critical to provide clarity on what scenarios should be modelled and then used to determine the appropriate level of financial assurance required. The assurance then provided (whether insurance or otherwise) would have to be relevant to that scenario.

In some contexts the credible worst-case spill would be a loss of well control (if multiple wells the one with the highest potential uncontrolled flow-rate) and so that is what should be modelled, whereas for others it could be a loss of containment from the largest storage tank on a FPSO. It is critical that where insurance is used there is nexus between the scenario driving the required assurance level and the nature of the insurance held (i.e. OEE insurance responds to uncontrolled well scenarios but is irrelevant in relation to oil releases from processing equipment or storage tanks). It should also be noted that over the life of a producing field these scenarios will change due to changes in equipment and particularly due to changes in well flow rates.[21]

The extent of the additional compliance costs and complexity created by Option 2C will depend partially on whether modelling is required to be undertaken specifically for this purpose or whether oil spill modelling undertaken already for other regulatory purposes (e.g. Oil Spill Response Plans under Maritime Rule 131 or Marine Consents under the EEZ Act) to be used. As noted above cost impacts are hard to estimate in the absence of key details and without applying the fully designed regime.

We also note that paragraph 67 of the discussion paper states that:

> "This option would have implications for operators as a scaled approach would increase the financial assurance requirement for many installations. Those operators would be required to either adjust their insurance coverage, or find additional financial guarantees, to cover their new requirement."

Given the current assurance level is NZ$27 million and New Zealand has no "dry gas" fields, we note the assurance requirement will be increased for <u>all current installations</u> as even where relevant scenarios suggest no potential shoreline impact the required level would still be up to NZ$50 million (Band 1). We are also concerned with second sentence in this paragraph as it suggests either a misunderstanding of level of current insurance provision by the industry (already far above the current regulated level) and/or an aversion to refining the scope of assurance, which is fundamental to achieving the levels of assurance proposed in the discussion paper.

[21] Flow rates for producing wells will generally diminish over the years they are in production due to reducing reservoir pressure. Oil wells can reach a point where they no longer flow without the use of artificial lift and at this time such wells cease to pose a risk of uncontrolled flow.

QUESTION 6: What would be a reasonable threshold (in bbl/km) for considering a section of shoreline 'affected' in an operator's oil spill modelling undertaken to satisfy option 2C?

PEPANZ considers that a reasonable threshold for considering a section of shoreline 'affected' for the purposes of oil spill modelling undertaken to satisfy Option 2C would be approximately 7 bbl/km. This equates to $100g/m^2$ based on the assumptions outlined in the Appendix to the discussion paper and would align with the threshold recommended in the Australian Maritime Safety Authority's foreshore assessment guide as the acceptable maximum thickness that does not inhibit the potential for recovery and is best remediated by natural coastal processes alone.

A coat of oil in excess of $100g/m^2$ hydrocarbon thickness would be enough to foul animals and likely affect survival and reproductive capacity, while a stain ($<100g/m^2$) would be less likely to have such an effect.[22] This figure would also generally align with the modelling already undertaken in New Zealand for other regulatory purposes.

QUESTION 7: How should Floating Production Storage and Offloading (FPSO) vessels be treated?

Should the banded system (Option 2C) be progressed we consider the proposed approach to determining the financial assurance level for FPSOs outlined in paragraph 70 and Appendix 1 of the discussion paper is broadly appropriate. We note however that given FPSO's are stationary, it would be a very rare occurrence for the hull of a FPSO to be breached, which is what would be required to generate a large scale spill event. As noted elsewhere the regulatory requirements need to clearly provide for what is being assured as amongst other things FPSOs have different sorts of insurance.

Issue 3: Coverage issues with conventional insurance polices

QUESTION 8: Which is your preferred option? Why? What are the strengths and weaknesses of each option?

PEPANZ considers that Option 3B (refine the scope of financial assurance) is the only appropriate option and must be progressed to ensure that any increased quantum of required assurance can be met.

Option 3C would provide limited practical advantages over Option 3B in practice whilst imposing additional costs and complexity on industry. Option 3A would be unworkable should assurance levels be increased significantly as proposed.

Option 3A

The status quo (Option 3A) is highly problematic at present. Requiring guarantees to be provided because insurance with substantially higher values has proven to be generally incompatible with the requirements is a poor approach.[23]

We note however that the discussion paper in some places appears to overstate the difference in scope between insurance policies and the very loosely defined liability provisions in the MTA relating to third parties. Insurance policies, such as OEE, provide coverage for damage to or loss of use of property by third parties and so the gap relates to pure economic losses, not all third party losses.

[22] Drawn from marine consent applications made to the EPA.
[23] As is noted in paragraph 78 of the discussion paper.

Option 3B

Option 3B is appropriate as it would align the assurance requirement with the types of global insurance policies designed for well control events that are held by the industry around the world and that are commonly used to meet similar assurance requirements. Refining the scope would also bring it into more into line with international norms (e.g. United Kingdom, Australia and Norway) where scope for economic losses is more clearly defined, thereby making it insurable.

In implementing Option 3B it may be more practical to spell out in the replacement Maritime Rule what the assurance needs to cover rather than trying to reconcile how it differs from “losses of profit from impairment of the environment”, given the inherently uncertain scope of that concept. It will also be necessary to consider the potential interplay between section 385J of the MTA and instruments with a refined scope provided under section 385H.

Paragraph 83 of the discussion document refers to the risk of non-recovery for third parties which suffer losses of profit from impairment of the environment, because funds would not be <u>guaranteed</u> for this aspect of liability. In practical terms this risk would only materialise if there was an event and the company/ies holding the permit were unable to meet any legitimate claims. We note also that the reference in paragraph 82 to what is required (e.g. clarifying acceptable conditions, deductions etc.) if Option 3B is progressed, is not limited to Option 3B and is equally if not more applicable to Option 3C.

Option 3C

Option 3C would make the New Zealand regime an outlier and would impose costs and complexity on industry for limited benefit. Identified problems with Option 3C include:

- Depending on how this was applied there could be costs and complexities in meeting an obligation of this type, even though responding to costs of this scale should be within the scope of relevant industry participants, thereby raising questions as to the cost/benefit of this regulatory approach.
- Applying this at the current assurance level of ~$NZ 27 million (as proposed in paragraph 84) is arbitrary.
- The current level applies to all elements of liability so to apply it to only a part of an element of this represents a major change. This is noted but somewhat understated in paragraph 86 of the discussion paper.

Option 3C effectively tries to sidestep, rather than solve, the issues with the potential inability to insure what is a wide, highly uncertain and poorly defined scope of economic losses under the MTA. It would be better to instead more clearly define “losses of profit from impairment of the environment” in such a way that this liability can be more clearly scoped and therefore insured in an integrated manner. In our view, favouring Option 3C would confirm that fundamental reform of Part 26A of the MTA is required.

With regard to Option 3C we also note it is not clear whether having two separate elements of assurance (losses of profit and well containment/clean-up) under Part 102 is compatible with the overarching legislative provisions in Part 26A of the MTA. Specific provision within Part 102 would be required to cover for the two different types of assurance being contemplated (i.e. well containment/clean-up aspect and seemingly a distinct aspect for third party losses of profit), which could be met in quite different ways for a single installation at a single time. For instance if multiple instruments resulted in a single certificate of insurance being issued we note the potentially problematic interplay between the operation of section 385J of the MTA and an insurance policy/policies or other instrument ("the insurer") that provides for many of, but not all of, the potential liabilities under sections 385B, 385C, and 385D of the MTA.

Paragraph 80 refers to "Redress for third party losses of profit would need to be sought through a civil claim and would not be guaranteed." It is important to note that even if "assured" redress would only be made following either a claim being made to a process run by the permit holder and/or its insurer or through court action. Even if claims were made directly to an insurer they would not be "guaranteed" to be successful. In this place the discussion paper appears to conflate the issue of whether assurance has been provided to meet claims that might be made, with whether any particular claim would be successful.

QUESTION 9: What would be the implications if options 3B or 3C were chosen?

Option 3B would have positive implications for the industry as it would allow conventional insurance policies to be used to satisfy the financial assurance obligations. Furthermore, in order for the assurance to be sought at the levels proposed for well containment and for clean-up and compensation the scope of financial assurance needs to be refined (i.e. Option 3B must be progressed). As discussed above we support clarity being provided in the Maritime Rule or supporting guidance material regarding to what exclusions, conditions and deductions would be acceptable for an insurance policy, or other instrument, to be accepted as financial assurance.

As noted above, Option 3C would make New Zealand an outlier compared with other jurisdictions and would impose additional costs and complexity on the industry. Companies would be forced to potentially pay twice to put in place different kinds of assurance. As well as industry having in place substantial assurance they would likely be required to then likely put in place further separate assurance, which would be out of step with international arrangements and make treatment of this sector disproportionate to others in New Zealand. Given the surrounding legal framework (e.g. financial capability tests already applying under the *Crown Minerals Act 1991*) we consider this approach is unnecessary. By frustrating, rather than facilitating investment, this would also make New Zealand a comparatively less attractive place for investment, which would be inconsistent with Government objectives for the energy sector and wider economy.

Other operational matters

As we have outlined earlier in this submission the design of Part 26A of the MTA is as a consequence of its maritime origins not aligned with the reality of how offshore oil and gas operations are organised in New Zealand and around the world. We consider these fundamental issues suggest review and reform of Part 26A of the MTA is warranted, beyond simply changes to assurance under Part 102. This would enable the key issues to be fully worked through and the interplay between different kinds of assurance with section 385J of the Act to be fully considered.

The final section of the discussion paper titled "Other operation matters" touches on some of the key issues and in this section we comment on these in turn.

Joint ventures and multiple installations

We support the comments in paragraph 89 that JVs that hold permits under the *Crown Minerals Act 1991*, which are the entities undertaking offshore petroleum exploration and mining operations, are responsible for establishing how they meet the financial assurance requirements. In order to facilitate continuing investment it is critical that the requirements can be met in a manner consistent with standard commercial practices and JV arrangements.

The discussion paper accurately outlines in paragraph 89 that there are two common approaches to assurance within joint ventures:

> "entities may provide a proportion of the financial assurance obligation that represents their interest in the installation. Alternatively, one entity may provide the entire financial assurance obligation on behalf of all other entities."

The most common approach is the former where each commercial participant in the joint venture entities provides a proportion of the financial assurance obligation that represents their interest in the facility or well. The JV participants have contractual obligations to each other and they are joint and severally liable for activities occurring in the permit. The parties to the JV are thus incentivised to ensure that each party has appropriate assurance in place.

Where one entity currently provides the entire financial assurance obligation on behalf of all other entities and the financial assurance requirement increases substantially, that entity is more likely to pass the obligation back to the individual entities. This could put pressure on smaller entities if it requires increased provisions to be made (with associated increased costs). Unduly high assurance obligations could also jeopardise smaller entities entering the New Zealand market or could mean proposed asset sales or farm-ins may not go ahead due to this being a deterrent to the potential purchaser.

The discussion paper seeks comment on issues with the status quo that need to be considered in regard to how joint ventures (e.g. permit holders) meet the financial assurance requirements. As outlined previously the status quo cannot continue with regard to the application of the financial assurance requirements because it has proved seemingly impractical to utilise insurance to meet these current $27 million requirement, and this <u>cannot</u> remain the case when the requirements increase to hundreds of millions of dollars. Specific issues that need to be addressed in replacement assurance requirements that relate to JVs in particular are:

- Companies will generally be involved in multiple joint venture permits in New Zealand and/or around the world and they generally have insurance arrangements in place across all their interests, not separate insurance arrangements for each permit. Utilisation of these needs to be acceptable for meeting assurance requirements so long as terms and conditions are in line with acceptable norms.

- Each insurance policy (or other assurance instrument) held by a participant in a joint venture will potentially differ in terms of limit and detail (e.g. different deductibles) but so long as the conditions of each meet conventional baselines and the limit of each is at least equal to the required assurance level (on a proportional basis) this should be acceptable to the regulator.

- How assurance requirements for specific permits are overseen efficiently throughout the course of a year if the joint venture participants have different insurance renewal dates and also interests in multiple permits, which is likely. New Zealand may be just a small part of a company's international portfolio.

- The different policy timing, different financial mechanisms and each entity having one or more methods of covering its portion means that complexity and administrative challenges arise. The burden of additional administrative complexity would fall on the regulator as well as industry participants.

We support the following proposal in paragraph 91 of the discussion paper on the basis that it relates to <u>both</u> multiple installations within a field/permit as well as where a company is a party to interests in multiple joint ventures in potentially both petroleum production (producing wells and production facilities) and petroleum exploration activities (exploration wells). The aggregate costs approach alluded to in that paragraph, but not favoured, would be completely unnecessary and unworkable and out of line with international practice.

> "it is considered sufficient that operators have financial assurance for highest cost installation amongst their portfolio of New Zealand operations, rather than the aggregate costs from multiple incidents. This financial assurance would also be used to meet their lower requirements for other installations in their portfolio."

As noted earlier in this submission there are inherent issues with the use of the term "installation" that it would be desirable are addressed to increase the clarity of the assurance requirements.[24]

Fundamentally, any implementation process should allow each company to establish compliance in a straightforward way across their portfolio. Most companies involved in have multiple interests in offshore permits (in many cases exploration and production) and these are often covered by the same insurance policies etc.

In Australian this is done by way of declaration by oil companies, and for companies with many interests a titleholder (company) may consider submitting a Financial Assurance Declaration covering multiple titles (permits) for which they are the registered holder. In the UK there is a process which requires licensees to declare that they understand their obligations and that they have and will maintain assurance in compliance with these obligations with the regulator able to ask for evidence of assurance (e.g. insurance certificates) when they see a need to do so. How this is managed under different scenarios is discussed in some length by the UK guidance on this topic and we suggest this is considered in taking forward the proposals in the discussion paper.[25]

We recognise the framework under the MTA and Part 102 is different but it is important compliance costs are minimised where possible. A straightforward approach would be for each company to provide to the regulator a certificate of insurance that demonstrated they held insurance of an appropriate type to an appropriate level to meet their obligations. Using appropriate certificates and avoiding any need for the regulator to specifically consider every individual insurance policy would significantly streamline compliance for companies and the regulator and minimise compliance costs.

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[24] For example for each well within a single drilling campaign there could be a different quantum of assurance and different parties, even if using a single rig operated by the same operator - because for each well the particulars will be different and different permits usually have different joint venture participants (even if they might overlap to some extent). Also we note that section 385H of the MTA provides that every regulated offshore installation is required to have a certificate of insurance when in NZ waters and so how this would work for those times when a MODU is in transit between permits, or in port after completing work, may require thought when the assurance is about individual well related risks.

[25] Refer to section 3.5.4 of Guidelines to assist licensees in demonstrating Financial Responsibility to DECC for the Consent of Exploration and Appraisal Wells in the UKCS, Issue 1 November 2012, UK Oil and Gas Association.

Currency

Given that insurance policies are generally denominated in $US (sometimes also $A or EUR) PEPANZ has advocated for the ability to use this currency for the assurance requirements and so support the proposal in the discussion paper. This reduces the issue of requiring insurance limits to be reworked year on year simply due to exchange rate fluctuations, which could become a significant issue given the substantial levels of assurance that will be required. Also, should an emergency situation occur a substantial proportion of the costs (particularly for well containment) would likely be incurred in $US.

Next steps

This review has been underway since 2013, and whilst no new exploration drilling is imminent it is important that a revised regime is introduced so that those permit holders planning to drill wells within the next 2 to 5 years can plan these substantial investments with confidence as to the rules applying. Policy changes proposed in this review need to be considered carefully but then progressed swiftly.

Once policy decisions are made it is important that the affected industry is consulted on the revised/replacement Maritime Rule before it is finalised. Ensuring the design of the new framework and the detailed drafting appropriately gives effect to policy decisions and aligns with commercial practices and insurance norms is critical to ensuring that the new regime is workable in practice.

Transitional matters will need to be sensibly provided for so that any changes in assurance levels and requirements apply with sufficient notice and only once certificates of insurance in force expire. To do otherwise would be unnecessary and potentially unworkable. Insurance policies are renewed annually (on varying dates) and so it would impose cost and complexity and may not be possible for industry to make changes more quickly than this. Given assurance levels held by industry participants are much greater than the current regulatory requirement this poses little if any risk during the transitional period.

We advocate for a revised Part 102 to be published by the middle of 2017 if practicable, with a possible consequent implementation date of 1 January 2018. This would give time after the new requirements are confirmed for industry participants to adjust their assurance (if necessary) before the new requirements come into force. It would mean that as current certificates of insurance expire from 1 January 2018 they would need to meet the new requirements.