NORTHERN TERRITORY GOVERNMENT

DEPARTMENT OF **PRIMARY INDUSTRY AND RESOURCES**

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File Ref: E2016/0036

The Honourable Justice
Rachel Pepper
Hydraulic Fracturing Taskforce
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By email: fracking.inquiry@nt.gov.au

Dear Justice Pepper

RE: HYDRAULIC FACTURING INQUIRY – INFORMATION REQUST

I refer to your letter of 1 August 2017, where pursuant to section 9 of the *Inquiries Act* you requested a response to a number of matters. Some information associated with this particular response should not be made publically available as it contains information for which the release is restricted under section 61 of the *Petroleum Act*.

Documents referred to in this letter are made available on a data disk submitted separately.

The Department of Primary Industry and Resources (DPIR) responds to your queries as follows:

1. Well integrity

Question

In their submission, Lock the Gate quote from the submission that the International Association of Hydrogeologists made to Dr Hawke's 2014 Inquiry into hydraulic fracturing in the Northern Territory:

'Well integrity is of concern in the NT because some groundwater environments in the NT are naturally corrosive. An example of the effect of corrosive water on cementing and casing in the NT is provided by deep oil exploration wells (McDills and Dakota) drilled in the Perdika/Great Artesian Basin in the 1960s. (The Perdika Basin is one of the prospective unconventional shale gas areas of the NT). Now, some fifty years later, the steel casing has almost entirely corroded away, resulting in inter---aquifer contamination. This well required expensive rehabilitation works to stem artesian flow (Humphreys and Kunde, 2004). This single bore cost the Territory and Commonwealth Governments $500,000 to plug as the company responsible for the well was insolvent. This example highlights the issue of operator insolvency due to the boom and bust cycles of oil and gas development which complicate efforts to hold liable parties responsible and provide for timely environmental reclamation."

Please comment on the above statement and include a discussion about the impact that the use of modern well design and construction practices has on long term well integrity.

Please also comment on how, under the current regulatory framework, the costs associated with remedying any environmental damage associated with the possible failure of an abandoned well are distributed between the taxpayer and the interest holder in the following scenarios:

- if the interest holder becomes insolvent while it holds the relevant petroleum interest;
- if the interest holder transfers the tenement to another entity; or

- if the interest holder surrenders the tenement or the tenement is cancelled.
Please identify any regulatory or other reforms that should be made to increase the transparency and accountability of the current system and, in addition, to the extent the taxpayer may be liable for any residual remediation costs under the current system, how this can be avoided.

McDills No.1 well incident

In 1965, the McDills No1 (McDills) petroleum well was drilled as a deep petroleum exploration well before the current legislation and regulations existed for petroleum activities. The well did not intersect economically developable hydrocarbons and was properly decommissioned as a petroleum well, ensuring any oil and gas reservoirs were isolated. McDills well was then converted to a water bore and subsequently transferred to the landholder who then assumed liability for the well's maintenance and operation. Sometime after it had been converted to a water bore, the well lost integrity. As a water well, McDills was exposed to the high salinity Great Artesian Basin water and the well head corroded.

A description of the McDills well rehabilitation and a discussion about well integrity practices is provided at Attachment A. and the full report on Rehabilitation of flowing bores in the NT Great Artesian Basin at Attachment B.

Under current legislation DPIR would require a thorough assessment of the suitability of the materials in the well and ensure they are fit for purpose, if a well was to be used as a water bore following decommissioning for petroleum. The required standards of construction materials and techniques today are far in advance of those in the 1960's. DPIR considers that past practices of converting petroleum wells into secondary purpose a such as a water bore are no longer necessary as petroleum operators employ licenced drillers to drill properly constructed water wells, which, if agreed can be used by the landholder at a later date.

DPIR ensures that the NT Government holds sufficient indemnities, securities and rehabilitation bonds and guarantees to ensure that government does not become liable for any remediation costs resulting from oil and gas activities. When wells are decommissioned and all rehabilitation requirements are met, which may include the transfer of certain assets (such dams, water bores and roads) to the pastoralist, DPIR returns the rehabilitation bond to the title holder. Notwithstanding, the title holder remains liable for any environmental issues that may be discovered after the closeout of a petroleum site and/or surrender of the title through indemnities required for the grant of an exploration permit, retention lease or production licence.

At no stage did Amerada Petroleum claim insolvency. With subsequent mergers, becoming known as Amerada Hess Corporation now known as Hess Corporation, an American global independent energy company engaged in the exploration and production of crude oil and natural gas, headquartered in New York City. The McDill No1 well incident was not a result of petroleum operator insolvency.

Impact of modern well design on long-term well integrity

Currently, requirements for well construction, operation and decommissioning are prescribed in the Schedule of onshore petroleum exploration and production requirements (Schedule). The Schedule is implemented by way of a Direction under s71 of the *Petroleum Act* and is reviewed regularly to ensure minimum standards and contemporary best practice is applied during the design, construction, stimulation, testing, production and operation, suspension and decommissioning of wells in the Northern Territory.

DPIR refers the panel to a number of recommended papers that have been written on this topic. These references are included at item 15 in this letter. DPIR provided detailed information regarding requirements for well design and construction in the submission provided to the Inquiry in April 2017.

Costs associated with remedying any environmental damage associated with the possible failure of an abandoned well

The objectives of decommissioning a well are: to permanently isolate all porous zones that may contain groundwater, to restore natural seals between subsurface formations as well as any perforated zones containing hydrocarbons. All decommissioning requirements for petroleum wells are outlined in Clause 329 of the Schedule. DPIR requires that companies submit evidence that those requirements are met through records of well construction and decommissioning such as mill certificates for tubulars (casing), cement composition analysis and sample testing records, volumes of cement pumped and records of pressure tests. Before accepting the surrender of a permit or licence, DPIR ensures that all wells have been decommissioned in accordance with regulatory requirements. DPIR's securities and rehabilitation bond requirements, environmental close-out procedures, regulatory requirements and legislative provisions have been submitted to the panel in several submissions and presentations, most recently in our letter dated 19 June 2017.

In response to your specific scenarios DPIR offers the following comments:

- Interest holder insolvency: DPIR will cancel the petroleum permit and use rehabilitation securities to decommission wells and rehabilitate any petroleum sites.
- Transfer of permit to another entity: DPIR ensures that either all decommissioning and rehabilitation requirements are met or that the transferee accepts all liabilities and obligations from the transferor and provides the department with a signed undertaking of such. This is only accepted if the transferee meets all eligibility criteria through a 'fit and proper person test', meaning that the transferee must be in good standing in the Northern Territory and/or elsewhere, and have the technical and financial capacity to accept the liabilities and obligations accompanying the petroleum interest transferred.
- Surrender of the permit: A surrender cannot be accepted until all permit obligations have been satisfied including decommissioning of wells and rehabilitation requirements.
- Cancellation of permit: Cancellation of a permit does not discharge the interest holder from liabilities and obligations under the permit. Before accepting the surrender of a permit or licence, DPIR ensures that all wells have been decommissioned in accordance with regulatory requirements. DPIR's securities and rehabilitation bond requirements, environmental close-out procedures, regulatory requirements and legislative provisions have been submitted to the panel in several submissions and presentations, most recently in our letter dated 19 June 2017.

Regulatory reforms to increase transparency and accountability

DPIR considers that the *Petroleum Act* provides the flexibility and enforceability to protect the interests of the Northern Territory. A properly decommissioned onshore well in the Northern Territory prevents an extremely low risk.

Shale wells have a number of advantages (compared to conventional wells, deep-water wells, high-pressure/high-temperature wells etc.) that further reduce the risks of well leakage after decommissioning:

- Shale gas (in the Beetaloo Sub-Basin) contains very low levels of corrosive gases (like CO2 and H2S).
- Reservoir pressure and temperature is relatively low and virtually depleted after production with no recharge.

- Shale is a natural seal and does not allow fluids to migrate.
- Chemicals used in the hydraulic fracturing stimulation process will have been produced during production, remain in-situ or react with minerals within the shale formation.
- There have been less than 250 wells drilled in the NT (compared to more than three million in North America) and there are no 'orphan wells' (wells that have not been properly decommissioned and for which there is no responsible operator) in the NT.
- In addition to the flexibility and enforceability of the Petroleum Act, the Schedule to the Act and the Petroleum (Environment) Regulations, DPIR's Engineers possess relevant academic qualification and experience and are current in access leading scientific and engineering papers and best practice standards when assessing wells for decommissioning. DPIR requires companies to submit detailed information of all well operations, including records of equipment used, volumes of fluids and cement, pressure tests and reporting on any incidents. Reporting requirements are listed clause 334, 335 and 336 of the Schedule. Well completion reports become publicly available subject to section 61 of the *Petroleum Act*. All information is analysed by a professional team of DPIR engineers.

In March 2016, Dr Tina Hunter reviewed the draft Petroleum (Environment) Regulations. Dr Hunter recommended that the regulatory framework should provide for independent certification of wells. This recommendation was given effect through an amendment of the Schedule. Independent validation and verification are defined in the Schedule.

Clause 103 of the Schedule provides for independent validation and verification of the construction, alteration or reconstruction of drilling and production equipment, wells, safety systems and emergency facilities.

An additional reform that DPIR considers could provide greater certainty, transparency and accountability is an audit and verification governance framework of the DPIR Energy Division's processes and its implementation. The Australian National Audit Office[1] and Australian Government Department of the Prime Minister and Cabinet[2] provide useful frameworks for the implementation of governance frameworks for regulatory agencies.

DPIR identified suspended wells as an area of concern. Wells are sometimes suspended for extended periods and therefore require a comprehensive care and maintenance program. DPIR has, therefore, limited duration of suspension to two years. This forces interest holders to re-apply for well suspension every two years. Approval takes into consideration the company's risk assessment, care and maintenance programs and further plans for the well.

2. Flowback and produced water

Question

The Interim Report includes a discussion on the composition of flowback and produced water. As noted in the Report, these waters may contain geogenic chemicals from the shale formation that are of potential environmental significance. These chemicals will be in addition to those that were originally found in hydraulic fracturing fluid.

Interest holders are currently required to disclose the chemicals used in hydraulic fracturing fluids to DPIR. However, the identity and concentration of chemicals in formation and produced water do not presently need to be disclosed.

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[1] https://www.anao.gov.au/

[2] https://www.pmc.gov.au/regulation/commonwealth-regulators/regulation-performance-framework

The Inquiry's preliminary view is that the regulatory framework should include a requirement that:

(a) a risk assessment of the chemical composition of flowback and produced water be undertaken; and

(b) real time disclosure of the chemical composition of flowback and produced water should be required.

Please comment on these views.

DPIR supports the disclosure of analysis of flowback water. DPIR has developed guidelines stipulating baseline monitoring, testing and reporting requirements of hydraulic fracturing fluids and flowback water. The quality and testing of flowback water may not be necessary on every (production) well if hydraulic fracturing fluids and stimulated formations are the same. Testing and analysis is of greater importance during exploration and appraisal drilling to assess environmental risks and potential human health impacts. That said, testing of flowback fluids may take some time as the composition of flowback fluids changes over the duration of the initial flowback phase and later phases.

DPIR's considers that the current regulatory framework is sufficiently robust to require reporting and disclosure of flowback fluids to the department. Given the early stages of exploration, guidelines on the exact nature, frequency and method of the tests are still evolving.

3. Solid waste management

Question

As noted in the Interim Report, the solids produced by drilling represent a substantial waste stream associated with the production of onshore shale gas. In the United States, the disposal of large amounts of drill cuttings produced by a full-scale industry is the cause of considerable concern given the nature of this material and its potential to leach organic and inorganic components into the near surface environment.

A strategic management issue for any potential shale gas industry in the Northern Territory will be the question of whether solid waste should be contained in a purpose-built and engineered centralised facility, or contained and managed on site, as is currently the case for the exploration regime.

Please indicate DPIR's current position on this issue.

In the NT experience, testing of drill cuttings has not revealed radiological isotopes (normally occurring radioactive materials – NORMs) in concentrations sufficient to trigger nuclear waste disposal requirements in accordance with Northern Territory Radiation Protection Regulations and the National Directory for Radiation Protection Schedule 4.

DPIR calculated that the drill cuttings produced from a 6,000 m long (measured depth) well comprise about 400 m^3 (Table 1). Therefore, a multi-well pad of 10 wells would 'produce' approximately 4 tonnes of drill cuttings.

Table 1: drilling cutting volumes one well

	casing size	hole size	depth	area	volume
	inch	inch	m	m2	m3
Conductor	30	36	50	0.66	33
Surface casing	20	26	200	0.34	51
Intermediate	13.375	12.5	1500	0.08	103
Intermediate	9.625	12.25	2500	0.08	76
Production	7	8.5	6000	0.04	128
Well cuttings					**391**

Cuttings will consist of a number of lithologies including limestone, sandstone, clays and shales. Testing of shales in the Beetaloo Sub-Basin did not reveal radiological isotopes (normally occurring radioactive materials – NORMs) in concentrations sufficient to trigger nuclear waste disposal requirements. Of note, drilling fluids do not contain harmful chemicals that would render the drill cuttings unsuitable for onsite disposal and drill cuttings are not exposed to hydraulic fracturing fluids.

If the composition of the cuttings is confirmed to be benign, DPIRs position is that the preferred treatment of drill cuttings is onsite disposal with consideration given to beneficial use for road construction for example.

In relation to NORMs, Origin Energy analysed samples of drill cuttings to confirm levels of Uranium (U), Thorium (Th) and Potassium (K) for three exploration wells being Kalala S-1, Amungee NW-1H and Beetaloo W-1. Origin's conclusion that NORMs did not exceed Northern Territory NORMs exemption levels was independently verified by Radiation Professionals[3], a specialised radiation management service provider to the oil and gas industry. Please refer to Attachment C for supporting information.

Clause 213 of the Schedule explicitly requires the Minister to be informed of any radioactive substances, compliance with Northern Territory legislation and the management of any radioactive materials.

4. Infrastructure requirements

Question

DPIR has estimated the number of wells that would be required for a full scale industry. These estimates appear to be different to the estimates provided by industry, which propose around 150 drilling pads and 1000 wells.

Please comment on the differences between the estimates provided by industry and describe how DPIR arrived at its estimates.

Please also provide details on the expected:

- initial size of well-pads
- size of well-pads during the operation phase
- length and clearing width for collector pipelines
- lengths and clearing widths of any access roads and other required easements that are not contained within pipeline corridors.

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[3] http://radiationprofessionals.com/

Please also comment on how the Department proposes to minimise the surface footprint of development.

DPIR provided the panel with estimates of wells required to develop 20, 50 and 125 trillion cubic feet (Tcf) of gas respectively. Those estimates do not include any assessment of economic viability of the onshore gas industry in the Northern Territory. The scenarios were based on supply (rather than demand) projections.

DPIR considered that a single shale well would recover between 6 – 12 peta joules (PJ) with a best estimate of about 8 PJ, based on assumptions in the APPEA-Deloitte report. DPIR settled on the 50 Tcf case as representative, emulating the Queensland onshore gas industry (current estimate is around 40 Tcf). Instead of 40,000 coal seam gas wells in Queensland 6,250 shale gas wells would be required in the Northern Territory to fully recover the amount of gas based on current techniques. (Note: the Deloitte report indicated 2,313 wells to recover 18 Tcf of shale gas in 20 years in the aspirational case).

More wells can be drilled from a single well pad and more gas can be produced from a single shale gas well than from a coal seam gas well. Conversely, one shale gas well pad would be equivalent to more than 50 coal seam gas well pads. Therefore, surface footprint, including roads, pipelines and gathering stations, is substantially smaller than for coal seam gas development, having greater flexibility in well pad placement and taking advantage of existing roads to minimise clearing requirements.

Industry well estimates

As far as DPIR can ascertain from the Interim Report and assuming recovery of about eight peta joules per well, the estimates provided by Origin and Santos would recover about 4 Tcf of gas (see calculations below). Origin has also stated that development would cover an area of 500 km^2. Origin's combined acreage over three permits (EP76, EP98 and EP117) over the Beetaloo Sub-Basin is 16,145 km^2. The amount of gas Origin and Santos propose to develop may be verified in two ways assuming;

One well recovers 8 PJ gas
1 TJ (tera joule) = ~1 MMscf (million standard cubic feet)
1 PJ (peta joule) = ~1 Bcf (billion cubic feet)
1 Tcf (trillion cubic feet) = 1,000 Bcf = 1,000,000 MMscf

1. 500 wells x 8 Bcf = 4,000 Bcf = 4 Tcf
2. 500 TJ/day x 365 days x 25 years = 4.6 Tcf

Economic viability aside, DPIR considers that given the apparent large resource potential and number of wells required to extract it, the scenarios presented by industry do not fully represent the potential (and potential impact) of the onshore gas industry in the Northern Territory. DPIRs role is to administer the *Petroleum Act* as directed by the Minister. The objective of the *Petroleum Act* is to: "provide a legal framework within which persons are encouraged to undertake effective exploration for petroleum and to develop petroleum production so that the optimum value of the resource is returned to the Territory".

Regulatory framework

The Minister may grant petroleum Exploration Permits that contain exploration work commitments that must be performed by title holders. The objective is to discover economically recoverable petroleum by the end of the term of the permit. Following discovery of petroleum, a title holder is obliged to either apply for a retention lease, production license or relinquish part or all of the permit so that it may be re-released to encourage an active and competitive petroleum sector. The Act allows for the grant of a Production Licence over 12 contiguous blocks (each block is about 80 km^2 in size). Under the current requirements of the *Petroleum Act,* a title holder can apply for a production licence to develop an area of about 1,000 km^2.

In order to obtain a production licence, a title holder must submit a field development plan for approval accompanied by a reservoir management plan and an environment management plan (EMP). Given the nature and scale of development, the proposal would first require assessment by the Northern Territory Environment Protection Authority (NTEPA) under a Notice of Intent (NoI). This would likely result in a requirement for an Environmental Impact Statement (EIS) under the current *Environmental Assessment Act.*

There is no limit on the number of production licences that could be considered under one EIS and in fact, it would be advantageous to assess the development of an area in aggregate. The company would gain certainty about project development, with government better placed to assess overall and cumulative risks and impacts.

A positive recommendation from the NTEPA about the proposed development does not override DPIR requirements. For granting a production licence and approval to commence production drilling activities, these include an approved EMP, field management and reservoir management plans and detailed drilling programs among other requirements. For environmental protection and optimisation of benefits to the Northern Territory, the production licence may be issued with conditions addressing such matters as the rate of development and production.

Surface footprint

Shale developments in North America have increased the number of wells per pad. Some development in Northern Alberta may have in excess of 35 wells per pad. Benefits of multi-well pads include reductions in equipment movements, overall number of well pads and associated service roads and pipelines, reducing the total "footprint" of the project, often by over 50%. In some cases, rig moves have been cut by as much as 75% in multi-well pads.

DPIR considers that it is premature to establish a firm number of wells per pad and advises that it considers15 wells per pad are possible. This may further depend on the potential of the different shale formations in the Beetaloo Sub-Basin which in addition the Velkerri B shale include the Velkerri A, Velkerri C and the Lower Kyalla subject to further exploration. DPIR advised the panel that 15 wells per pad was considered a best estimate in light of the (insufficient) available data in its response to the panel's request for information of 27 April 2017. DPIR notes that industry used 8 wells per pad and has therefore re-calculated the footprint associated with industry's projected development of a 500 km^2 area during development and during operations with the following assumptions:

Wells per pad	8
Number of pads	63
Drainage area per well	1 km^2
Pad size during development / operation	350 x 350 m / 80 x 40 m
Roads per pad	1
Road/pipeline corridor in construction /operation	30 m / 10 m

Table 2: Footprint of shale gas development 500 km^2

Footprint Aspect	Value	Unit
Drainage per well	1	km^2
Drainage per pad	8	km^2
Indicative spacing (average)	5.7	km
Clearing per pad (350mx350m)	12.25	ha
Total pad footprint in development	**766**	**ha**
Pad footprint in operation (80mx40m)	0.32	ha
Total pad footprint in operation	**20**	**ha**
Proportional footprint for pads in development	**1.53**	%
Proportional footprint for pads in operation	**0.04**	%
Road / Pipeline footprint per pad in development	17	ha
Total Road / Pipeline footprint in development	**1,061**	**ha**
Proportional footprint for Roads / Pipelines in development	**2.12**	%
Footprint road per pad in operation	5.7	ha
Total footprint for roads in operation	**354**	**ha**
Proportional footprint roads in operation	**0.71%**	%
Total proportional footprint in development	**3.65%**	%
Total proportional footprint in operation	**0.75%**	%

Footprint impacts may be reduced by planning roads and interconnecting well pads via existing cleared tracks and firebreaks and the placement of well sites away from sensitive ecological receptors.

Minimum well spacing

DPIR does not support mandating minimum well spacing or a minimum number of wells per pad to try and minimise surface impacts. A primary aim of any field development is to optimise the recovery of hydrocarbons from the reservoir leaving minimal stranded hydrocarbons in-situ. Mandatory well spacing would jeopardise industry's capacity to optimise the full economic value of the development, which in turn would mean less benefit for Territorians.

Through the whole lifecycle of field development well pad location and numbers of wells per pad should also be dictated by key factors like environmental impact, quality of the shale, maximum hydrocarbon reservoir drainage and project economics as noted above.

Planning field development is based on the collection of a significant amount of technical and economic data about all of these factors. Planning for a particular field development should be done on a case by case basis. It is likely that field developments will be subject to the Commonwealth Environmental Protection and Biodiversity Conservation Act and will require an EIS evaluated by the NTEPA. In addition, activity EMP's must demonstrate that the impact:

- meets the principles of ecologically sustainable development
- reduces the impact on the environment to a level that is as low as reasonably practicable and is acceptable.

Mandating a minimum well spacing may lead to unwanted outcomes, including a larger footprint than otherwise would be necessary, to produce the same amount of gas.

5. Disposal of wastewater into aquifers

Question
The Schedule of Onshore Petroleum Exploration and Production Requirements
2016 provides that an interest holder must take reasonable steps to "prevent... the pollution of aquifers". There does not, however, appear to be an express prohibition on the injection of wastewater, treated or not, into aquifers.
While the Inquiry's preliminary view is that the injection of wastewater, whether treated or untreated, into aquifers should not be permitted, it is seeking additional information regarding the risks associated with this process and whether these
Please comment on this issue and identify any circumstances where, in DPIR's view, it would be considered appropriate to inject wastewater into an aquifer.

Any waste must be treated in accordance with a waste management plan included in the EMP for the activity. The disposal of any waste, or the injection of water that is not expressly included and approved as part of an EMP, is an offence against the Petroleum (Environment) Regulations and an offence against section 117AAC(1) of the *Petroleum Act*.

DPIR does not support flowback water disposal, or any other wastewater, into freshwater aquifers. If proven safe and environmentally responsible to do so under certain conditions, safeguards and water quality requirements, deep aquifers may be considered for use for the disposal of wastewater, but only if water in the receiving aquifer is non-potable and is not connected to any other aquifer system.

While mining and petroleum activities are currently exempt from certain provisions of the *Water Act* (section 7), there is no exemption for the disposal of wastewater into aquifers. This is because the wastewater would not be demonstrably confined to the petroleum site. Wastewater disposal into an aquifer requires an underground waste disposal licence under section 64 of the *Water Act* and unlicensed wastewater injection is an offence subject to section 62 of the *Water Act*.

DPIR would consider either the reuse, beneficial use or deep injection of wastewater into deep saline aquifers relying on advice from qualified hydrologists and experts from the Department of Environment and Natural Resources. Given community concerns about ensuring sustainability of freshwater in the Northern Territory, the concept of wastewater discharge into freshwater aquifers is not under consideration.

As groundwater quality can vary widely, DPIR suggests the Australian and New Zealand Guidelines of Fresh and Marine Water Quality provide a useful guide[4].

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[4] https://environment.gov.au/system/files/resources/53cda9ea-7ec2-49d4-af29-d1dde09e96ef/files/nwqms-guidelines-4-vol1.pdf

6. Storage

Question
Origin and Santos propose to minimise the risk of containment overtopping by designing to 1 in 100 year rainfall events. Lock the Gate, however, provided an example of a storage pond that overflowed during a recent wet season. This suggests that it may be more appropriate to design for a maximum probable precipitation event coupled with an appropriate maximum operating level. Please comment on leading practice mechanisms available to avoid containment overtopping, including the use of special purpose above ground tanks to store wastewater.

The Lock the Gate (LTG) submission makes two claims:

1. That holding ponds containing fluids overflowed in the wet 2015 season, and
2. That the overflow fluids contained hydraulic fracturing fluids.

DPIR maintain that the claim that the ponds were ever at risk of overflowing is incorrect, based on the following:

1. Pictures supplied in the LTG submission clearly show a substantial freeboard and do not show any evidence of overflowing. Origin maintained a rig crew (drilling contractor Saxon) on site during the wet season, providing regular updates to DPIR. Reports from the site indicated that freeboard was never below 2 m.
2. In answering the second claim, Origin did not conduct any hydraulic fracturing activities in 2015 (only drilling activities). Information, previously provided to the panel, from Origin's 2016 hydraulic fracturing campaign on the Amungee NW-1H well, demonstrates that flowback fluid was captured in above ground ponds that have several protective liners (two HDPE liners and a protective geo-liner to protect against any punctures).

As noted above, the Petroleum (Environment Regulations) require that an activity EMP identifies all potential risks and demonstrates to DPIR that the activity as proposed:

- meets the principles of ecologically sustainable development and
- reduces the impact on the environment to a level that is as low as reasonably practicable and is acceptable.

An activity EMP must identify all risks and detail how they will be managed, including seasonal events.

DPIR is satisfied that the meteorological data and fluid management measures used by Origin to eliminate the risk of overflowing of ponds was adequate.

7. Discharge into waterways

Question
DPIR has advised the Inquiry that: *"Current practice requires that wastewater from hydraulic fracturing activities is fully contained on site."* Please advise whether this requirement is prescribed in the legislation and how it is enforced. Please also advise whether there is an express prohibition on the release of untreated wastewater into waterways or drainage lines.

Wastewater from hydraulic fracturing or drilling operations must be managed in accordance with a waste management plan under an approved EMP pursuant to the Petroleum (Environment) Regulations. Any proposal to dispose untreated wastewater into waterways would not be approved.

Should a proponent wish to dispose of treated wastewater by release into a waterway, the activity EMP would need to demonstrate that the disposal:

- meets the principles of ecologically sustainable development
- reduces the impact on the environment to a level that is as low as reasonably practicable and is acceptable.
- Meets appropriate water quality standards

The EMP would achieve this through establishing clear objectives, controls with performance standards and measurement criteria. An implementation plan that gives confidence that any adverse effects on the receiving waterway and its ecologically dependent receptors are avoided must also be provided. In addition, wastewater discharge into waterways requires a water discharge licence under section 74 of the *Water Act*. Unlicensed discharge is an offence against section 16 of the *Water Act*.

Mining and petroleum activities are currently exempt from certain parts of the *Water Act*, namely section 15, section 16 (only if confined to the petroleum site), Part 5 and Part 6 including Division 5 (only if confined to the petroleum site). Therefore, petroleum activities are not completely exempt from the *Water Act* when the activity extends beyond the petroleum site. Please note that Government has made the decision to remove the current exemptions from the *Water Act* and this is currently being progressed by relevant Departments.

8. Amungee NW-1H well data

Question

Following recent media coverage, the Inquiry understands that certain monitoring information regarding the Amungee NW-1 well is passed on to DPIR on a weekly basis. Please provide the Inquiry with a copy of that data, including an interpretation of that data.

[redacted]

9. Greenhouse-gas emissions

Question

The Panel has formed a preliminary view that, if the industry is given approval to proceed, the following mechanisms will be required to minimise greenhouse gas emissions, and in particular, methane emissions:

• implementation of leading practice standards for emission reduction (such as, for example, the United States Environmental Protection Agency's New Source Performance Standards, Permitting Rules for the Oil and Natural Gas Industry)

• baseline measurements of methane levels prior to development

• ongoing monitoring of methane levels at key points during exploration, development, and production.

The Inquiry invites comments on the above. In addition, please comment on:

1. the technologies that are currently available to obtain baseline measurements of emissions, including the possible use of drones

2. the scope, including the location, of any emissions monitoring that should occur during the exploration, development and production phases, such as, for example, wellheads during completion, liquids unloading, compressor seals and gathering stations;

3. the use of emission limits that, if exceeded, would trigger an investigation, make-good requirements and/or a penalty;

4. the need for transparency when setting emission limits; and

5. whether or not baseline measurements and on-going monitoring should be undertaken by an independent body.

The Inquiry also requests DPIR's comments on section 9.8 of the Interim Report, which has been duplicated at Attachment A.

DPIR agrees that management of greenhouse gas emissions is an important focus during any production stage of development where, if not properly managed, fugitive emissions could be a substantial contributor to the overall carbon inventory in the atmosphere.

In 2015 the NT Government released the onshore oil and gas guiding principles. In relation to air emissions, the following relevant operating principles are incorporated:

1. Planning field operations in a manner that will avoid or significantly reduce emissions from flaring and venting as far as practicable. This can include proximity to infrastructure and timing considerations.
2. Where flaring or venting cannot be avoided, ensure appropriate design and controls are put in place. Design and controls of sources must be developed giving consideration to:
   - Safety,
   - Health of nearby residents,
   - Environmental impacts of emissions,
   - Greenhouse gas considerations – particularly during venting.
3. Well design must limit or mitigate fugitive emissions. Examples include well casing design which eliminates routine venting to the surface, as well as ensuring isolation of the well throughout and beyond the lifetime of the gas field. Well designs chosen must be in line with relevant regulations.
4. Well heads must be regularly inspected for leaks and subject to a routine maintenance program. These must be in line with relevant regulations where applicable.
5. Plant and equipment which minimises emissions must be chosen where possible. Examples would include compressors run with electric motors rather than fuel burning engines, and natural gas engines rather than diesel engines.

Recent work by CSIRO indicates that fugitive emissions from gas production in Australia are estimated to account for 2.5 percent of greenhouse-gas emissions. The studies were focussed on coal seam gas production facilities (Day et al. 2014) and well completion activities (Day et al. 2017). The reports outline the field measurements and methodologies employed. Should the moratorium be lifted, these could be suitable to implement on shale gas operations in the Northern Territory.

DPIR puts forward some differences that may put the risks of fugitive emissions from shale gas development in the NT in perspective in comparison to the available research on coal seam gas in Australia:

- Shale gas can be developed with fewer wells, which reduces the number of wellheads, valves and instruments that may form a pathway for the escape of fugitive emissions.
- Shale wells can be co-located with eight or more wells per well pad, which aids in the measurement and control of fugitive emissions and again reduces the number of valves, instruments and other interfaces that may form a pathway for the escape of fugitive emissions.
- Shale gas development does not require a long 'dewatering' phase as is the case with coal seam gas development. Therefore, safe controlled unload and flowback (SCUF) tanks are not in use in shale gas completions. Instead during exploration, flowback fluids (gas and liquids) have been directed through a 2-phase test separator directing the gas to a flare that burns the gas. This process reduces the greenhouse-gas impacts. During development, it is expected that the gas will be captured and transported to a gas processing facility.

References to the CSIRO reports are included under section 15 of this letter. DPIR intends to develop guidelines for the management, elimination and mitigation, measurement and reporting of fugitive emissions to ensure best practice standards are employed to reduce and minimise greenhouse gas emissions. These practices may include, but will not be limited to, practices that have been identified by the US EPA Natural Gas STAR Program referenced in earlier presentation from DPIR to the panel.

DPIR is also involved in the round table discussions in South Australia that originated from the Roadmap for Unconventional Gas in South Australia initiative. Eight working groups established under the initiative hold round table discussions between title holders, suppliers, scientists and stakeholders. More information on this subject is provided under section 14 of this letter. Working group 5 is focussed on cost effective and trustworthy GHG detection[5].

DPIR develops guidelines or Codes of Practice by carefully examining best practice in other jurisdictions, scientific evidence and engagement with subject matter experts within government, universities and the CSIRO. Once a draft guideline is developed that identifies best practices and appropriate standards, measurement criteria and methodology etc., the guideline will be published for comment. While draft guidelines have been developed for water monitoring and chemical use and disclosure as well as a Code of Practice for Petroleum Wells, greenhouse gas guidelines are yet to be developed.

In collaboration with OSIsoft, Central Petroleum Limited and Charles Darwin University's Northern Australia Centre for Oil and Gas[6] (NACOG,) DPIR is working to implement a pilot project on remote monitoring of air quality where flaring occurs at the Mereenie Field in the Amadeus Basin. The goal of the project is threefold:

- to use oil and gas exploration and production data to deliver a step change in cost reduction
- to increase productivity in processing
- regulatory monitoring of air quality.

To ensure the impacts of oil and gas activities on greenhouse gas emissions are fully understood and mitigated, DPIR is supportive of baseline data collection, ongoing monitoring

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[5] http://petroleum.statedevelopment.sa.gov.au/roundtable_for_oil_and_gas/working_group_5_-_cost-effective_and_trustworthy_ghg_detection
[6] http://www.cdu.edu.au/oilandgas

during operations and monitoring after decommissioning until it is demonstrated that the risks of leakage from oil and gas wells are eliminated.

The panel's request for comment on the risk assessment provided at Attachment A of your letter, appears to be a useful tool when there is greater clarity around the potential magnitude of the unconventional gas industry, the rate of development and the regulatory model the Northern Territory would adopt.

10. Minimum standards

Question

In the Interim Report the Inquiry committed to explore:

"*mechanisms to ensure that minimum standards for environmental protection are guaranteed in the regulator framework, such as the requirement to undertake baseline studies prior to hydraulic fracturing*".

Please indicate whether DPIR supports the use of prescribed minimum standards in the regulatory framework and, if so, how minimum standards should be incorporated into the current statutory framework. Specifically, is it proposed that the *Petroleum (Environment) Regulations 2016* (NT) be amended to include minimum standards, or is it proposed that guidelines or other regulatory tools, such as Ministerial directions, be used?

In accordance with the office of best practice regulation[7] guidelines, DPIR is pursuing the implementation of a risk-based and outcome-focussed regulatory framework. However, DPIR supports the implementation of selective minimum standards.

Attachment E shows in graphic format the regulatory framework that is envisaged that requires that titleholders submit technical work programs (be it a survey management plan, well management plan, stimulation and testing management plan, field management plan etc.) accompanied by an EMP. These must identify applicable industry standards and be compliant with all applicable legislation, incorporating the requirements set out in departmental guidelines and codes of practice. An approved plan by the Minister for Resources becomes a legally binding document with which the title holder must comply. Non-compliant plans shall not be approved.

In this way, the regulatory framework is flexible. The legislation and regulations set the framework of what must be submitted for approval and how compliance is enforced, while the methods by which compliance is achieved can be developed and maintained in collaboration with relevant stakeholders, including subject matter experts, directly affected stakeholders and industry.

Much mention has been made throughout the panel's public hearings about the Code of Practice for Petroleum Wells in Queensland. Irrespective of the moratorium and potential ban on shale gas development, DPIR plans to adopt this Code of Practice (with potential customisation for the Northern Territory context) subject to stakeholder consultation. This will occur following the implementation of yet to be developed Petroleum (Resource Management and Administration) Regulations. Those regulations are proposed to closely follow the Commonwealth regulations for offshore *Petroleum Act*ivities and the Western Australian Petroleum (Resource Management and Administration) Regulations. The Code of Practice and the regulations will replace the Schedule of Onshore Petroleum Exploration and Production Requirements, finding the right balance between outcome-focussed and

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[7] https://www.pmc.gov.au/regulation/best-practice-regulation

prescriptive regulation. This work is necessary to ensure contemporary legislation for the ongoing regulation of the onshore petroleum industry regardless of the nature of the resource whether it be conventional or unconventional petroleum development.

The legislative framework will consist of acts, regulations, policies, codes of practice, guidelines and standards. The principal Act sets out the objectives, key principles, obligation and rights of title holders. Regulations are formed under an Act, specify the duty holder's obligations and are legally enforceable. Approved Codes of Practice are practical guides to achieving the requirements set out in the Act and Regulations. Approved Codes of Practice can be used in courts as evidence that legal requirements have or have not been met. Standards are documents that set out specifications and procedures designed to ensure products, services and systems are safe. Standards are voluntary unless the Standard has been called up into legislation. Standards called up into legislation, are legally enforceable, as are standards that are committed to in approved company plans.

Guidelines will identify applicable standards for various aspects of unconventional oil and gas exploration and development. Guidelines will outline the expectations the NT Government has about how aspects of petroleum exploration and development should be conducted. This will assist title holders in the development of plans for approval. While practices in guidelines are recommended, title holders may propose alternative methods of managing certain aspects. The title holder must then present a case to explain why the alternatively chosen method should be approved.

11. Regulatory capture

Question

The Interim Report made the following observation:

"The Panel noted the widely held view in the community that the DPIR is not independent from the industry. Some submissions noted that there was evidence of regulatory capture."

Please comment on this statement and describe any regulatory or structural reforms that DPIR has considered to ensure the independence of the regulator.

The Interim Report referenced two submissions in support of this statement:

Excerpt from the North Australian Rural Management Consultants Pty Ltd (NARMCO) submission reference number 186 states:

> "There is a risk that the regulatory body becomes reluctant to regulate. There are government agencies and community organisations who have capacity to highlight this behaviour should it become apparent.
>
> There is equally a risk that the regulatory body becomes overzealous in their role in response to a portion of the community who are anti-fracking. The industry has limited options to appeal such behaviour should it occur.
>
> NARMCO considers these risks to be acceptable, and they do not have a sufficient impact to warrant a ban on hydraulic fracturing."

Excerpt from Ms Sharon Bury submission number 189 states:

> "The same government department promoting the fracking industry must not be responsible for monitoring and regulating the industry. To allow this is a clear conflict of interest and provides no protection to the Territory public or the environment."

While these are statements without supporting evidence, DPIR acknowledges the observation of the panel that there is strong opposition to hydraulic fracturing in parts of the community that were represented at the public hearings. Naturally, DPIR takes these concerns very seriously and engages regularly with other oil and gas regulators to discuss how to build better relations with the community and to provide clear, accurate and objective information. DPIR recognises that community engagement and consultation are skills and competencies that must be developed.

A report published by the University of Pennsylvania, Penn Program on Regulation in collaboration with the Alberta Energy Regulator defined regulatory excellence in three core attributes of excellence:

> *Utmost Integrity*: This is about much more than just a lack of corruption; it is also about the regulator's commitment to serving the public interest, to respect the law, and to working with duly elected representatives.
>
> *Stellar Competence*: This is about the actual delivery of outcomes that maximize public value and the capacities built and actions taken to achieve a high level of performance.
>
> *Empathic Engagement*: This is about transparency and public engagement, but also about how respectfully the regulator and its personnel treat regulated entities, affected landowners, and all other concerned individuals.

The Northern Territory public service values are the following: Commitment to service, ethical practice, respect, accountability, impartiality and diversity.

DPIR is responsible for the administration of the *Petroleum Act*, *Petroleum (submerged lands) Act, Energy Pipelines Act and Geothermal Energy Act*. While any project may trigger an assessment under the Environmental Assessment Act administered by the independent NTEPA, the actual implementation of the project (with any conditions that may be recommended by the NTEPA or the Minister for Environment), is administered by DPIR on behalf of the Minister for Resources.

The objectives of the *Petroleum Act* are as follows:

3 Objective

(1) The objective of this Act is to provide a legal framework within which persons are encouraged to undertake effective exploration for petroleum and to develop petroleum production so that the optimum value of the resource is returned to the Territory.

(2) The legal framework provides for the following:

(a) the granting of petroleum interests to persons for exploration, production and ancillary activities associated with exploiting petroleum, and the renewal or transfer of those interests;

(b) clear statements about the role of government following the grant of petroleum interests;

(c) the promotion of active exploration for petroleum, and of the development of petroleum production, if commercially viable, by persons granted petroleum interests;

(d) the assessment of proposed technical works programmes for the exploration, appraisal, recovery or production of petroleum and of the financial capacity of persons proposing to carry out those programmes;

(f) the reduction of risks, so far as is reasonable and practicable, of harm to the environment during activities associated with exploration for or production of petroleum;

(g) the collection of information about petroleum exploration and production and the dissemination of that information;

(h) the efficient administration of this Act and collection of royalties;

(i) other matters in connection with exploration for and production of petroleum.

DPIR considers that the *Petroleum Act* outlines a clear framework for the effective exploration for petroleum and petroleum production so that the optimum value of the resource is returned to the Territory. As provided for in the Act, the DPIR Energy Division is responsible for title administration through:

- granting petroleum interests and the renewal and transfer (and surrender and cancellation) of those interests and is responsible for the promotion of active exploration for petroleum, and of the development of petroleum production, if commercially viable, by persons granted petroleum interests;

- the assessment of proposed technical works programmes for the exploration, appraisal, recovery or production of petroleum and of the financial capacity of persons proposing to carry out those programmes; and

- the reduction of risks, so far as is reasonable and practicable, of harm to the environment during activities associated with exploration for or production of petroleum.

While the Minister is ultimately responsible for decision under the *Petroleum Act*, there are two ways in which promotion of the petroleum industry is given effect within the DPIR:

1. The Energy Division is responsible for the release of acreage and the award of that acreage to prospective title holders that put forward the strongest case to develop Northern Territory petroleum resources and to ensure that the title holder does so in a forthright and diligent way, having regard to objective 3(2)(f) reducing risks, so far as reasonable and practicable, of harm to the environment during activities associated with exploration for or production of petroleum.

2. The Northern Territory Geological Survey is responsible for the collection of information about petroleum exploration and production and the dissemination of that information and is responsible for the promotion of the Northern Territory as a preferred place to invest in resource exploration.

DPIR consider that the Energy Division is appropriately removed from the promotion as described under (2) to provide effective regulation of the industry. The Department of Treasury and Finance is responsible for the collection of royalties.

<u>Utmost Integrity</u>

Employees in the public service strive to achieve the best outcomes for the Northern Territory and operate within the values of the public service. They are also required to operate within the framework of the *Public Sector Employment Act*. DPIR strives to operate with the utmost integrity and commitment to public sector values.

The panel requested whether DPIR has considered any regulatory or structural reforms to ensure the independence (integrity) of the regulator. DPIR supports transparency, independence and accountability. Steps taken thus far to improve transparency and accountability include the full disclosure of environment management plans (EMP) and chemicals used in petroleum operations and the preparation of a "statement of reasons" for approval of an EMP.

Further reforms that could be considered include governance systems such as a regulator performance management framework as outlined by the Australian Government Office of Best Practice Regulation and the Australian National Audit Office. A rigorous governance framework would provide DPIR with a clear way to demonstrate its independence and avoid allegations of industry capture.

Stellar competence

The panel may like to note various current regulatory authorities such as the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) or the Alberta Energy Regulator (AER) in Canada. Such authorities operate under a board of directors that are accountable to the Minister and must provide governance to ensure that regulatory objectives are met. Both organisations are funded by levies or fees on activities that recover the costs of regulation. NOPSEMA regulates work health and safety (including well and pipeline integrity) and environmental management. Title administration is delivered by the National Offshore Petroleum title Authority (NOPTA) within the Department of Industry, Innovation and Trade. The AER combines all functions. The key aspect, however, is that the regulation of work health and safety, process safety and environmental protection for the oil and gas industry are combined in a single entity.

Petroleum exploration and development requires multi-disciplinary teams to work together effectively to achieve good outcomes. Well integrity, for example, is directly related to environmental performance but is also closely related to safety. Therefore some jurisdictions have included the responsibility for well integrity with the Environment Protection Authority (New South Wales) where, in other jurisdictions, well integrity has become the responsibility of Worksafe (New Zealand). In Western Australia, these functions all sit within the Department of Mines, Industry Regulation and Safety (formerly the Department of Mines and Petroleum).

The benefits of a single dedicated regulator were outlined by Elmer P. Danenberger former Chief of the Technical Advisory Section at the headquarters office of the U.S. Geological Survey, District Supervisor for Minerals Management Service (MMS) with 38 years' experience in the regulation of the oil and gas industry in the Gulf of Mexico in his submission to the Montara Inquiry:

"*Safety and pollution prevention programs are more effective if a single agency is responsible and accountable for the regulation of operations. Unfortunately, legislative bodies do not always comprehend the safety and environmental risks associated with fragmented or compartmentalised regulatory regimes. These risks include regulatory gaps, overlap, confusion, inconsistencies, and conflicting standards. Also, a sufficient number of competent regulatory personnel may not be available to staff multiple agencies. Ideally, one agency would be responsible for all regulatory aspects of drilling and production operations. Safety and pollution prevention are inextricably linked and both should be regulated by this agency.*"

DPIR strives to collaborate effectively with all other NT Government agencies. We believe that relevant government agencies are working to achieve the best outcomes for the Northern Territory.

Emphatic engagement

The AER, NOPSEMA and DPIR recognise the importance of effective engagement with stakeholders. Stakeholder engagement has been a key theme in the implementation of the Petroleum Environment Regulations. DPIR recognises the need to implement an engagement strategy focussed on the facts and the manner in which the department regulates the industry.

DPIR considers that Western Australia, South Australia and NOPSEMA have all made useful inroads to improving stakeholder engagement. South Australia's Roadmap for Unconventional Gas was a promising initiative to engage the community about the potential benefits from the unconventional gas industry and the way in which the industry should be developed. Western Australia recognised the importance of stakeholder engagement and conducted a department-wide training program for its officers to improve the way the department interacts with stakeholders and the community. It has also established regional community liaison officers. The Western Australia Department of Mines and Petroleum Stakeholder and community engagement website is available and referenced at item 15 to this letter. DPIR also recommends the Guide to the Regulatory Framework for Shale and Tight Gas in Western Australia to the panel that describes the Whole of Government Approach in that state.

The panel may wish to consider additional references provided at item 15 to this letter.

12. Cost recovery

Question
Please indicate whether DPIR has considered implementing a cost recovery system under the Petroleum Act 1984 (NT). Please note the benefits associated with such a proposal.

In December 2002 the Australian Government adopted a formal Cost Recovery policy to improve the consistency, transparency and accountability of its Cost Recovery arrangements and to promote the efficient allocation of resources. The underlying principle of the policy is that entities should set charges to recover all costs of products or services where it is efficient and effective to do so, where the beneficiaries are a narrow and identifiable group and where charging is consistent with Australian Government policy objectives. Cost Recovery policy is administered by the Department of Finance and outlined in the Australian Government Cost Recovery Guidelines.

The policy applies to all Financial Management and Accountability Act 1997 (FMA Act) agencies now regulated under the Public Governance, Performance Accountability Act 2013. In line with the policy, individual portfolio ministers are ultimately responsible for ensuring implementation of Cost Recovery arrangements within their portfolios in a manner consistent with the Cost Recovery Guidelines.

In accordance with the guidelines any cost recovery or fee-for-service model must be consistent with the following principles:

- Efficiency and effectiveness.
- Transparency and accountability.
- Stakeholder engagement.

To enable cost recovery the responsible government entity must meet the following requirements:

- Have government approval.
- Have statutory authority to charge.
- Ensure alignment between expenses and revenue.
- Maintain up-to-date publicly available documentation and reporting.
- Conduct periodic portfolio charging reviews.

DPIR supports a cost recovery model for administration and regulation of the petroleum legislation for petroleum activities in the Northern Territory. A number of expert advisors have recommended such a model.

- The Hawke Inquiry report's primary recommendation states: *"Consistent with other Australian and international reviews, the environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory regime."* On page 157 of Dr Allan Hawke's Inquiry report, Dr Allan Hawke noted that: *"cost of this work (environmental baseline studies) could be recovered through tenement rentals or application fees if deemed appropriate by the NT Government."*
- Recommendation number 23 of Dr Tina Hunter in the NT "Petroleum Legislation Review" states: *"Recognising the significant effects of UGR Petroleum Activities, especially drilling activities, on the environment, water resources and landforms, on-site inspection of critical UGR well activities, including hydraulic fracturing and well abandonment, should be undertaken. The DoR should consider the funding of these Inspectors on a "Fees for Service" basis similar to the regulation of offshore petroleum safety."*
- Mr Sean Reddan's recommendation of "Energy Directorate's Regulatory Practices" states: *"Consider the application of a permanent cost-recovery model to self-fund its regulatory operations."*

DPIR currently charges fees for title administration matters as per the Petroleum Regulations, Schedule Fees and Amounts. Fees are defined as revenue units where 1 unit is $1.15.

Each jurisdiction applies different forms of cost recovery, for example:

- The National Offshore Petroleum and Environmental Authority (NOPSEMA) charges fees on an activity basis (such as drilling a well or conducting a seismic survey etc.). The fee covers assessment of proposed activities and compliance monitoring and enforcement requirements.
- South Australia and Western Australia charge title fees that cover the assessment, compliance and enforcement activities to deliver effective regulation of the petroleum industry.

The aim of cost recovery is to deliver cost-effective regulation of the oil and gas industry on a not for profit basis. This model has the potential to establish a well-funded and fully resourced regulatory function that is responsive to industry needs in terms of directing the regulatory effort where it provides maximum effect and community benefit.

13. Compensation

Question
Please describe how the Petroleum Act 1984 (NT) compensates traditional owners and pastoral lessees in the event a gas company causes damage to land, property or business operations.

The *Petroleum Act* provides for compensation and 'make good' resolution processes for traditional owners and land holders as follows:

Division 4 of the *Petroleum Act*

section 80 relates to security for compensation that may be payable to native title holders.

Before granting, renewing or varying a petroleum interest, the Minister requires an applicant to lodge a security, for the amount and from the person the Minister thinks fit for the purpose of securing the payment by the applicant of compensation that may be payable for the effect of the grant, renewal or variation of native title rights and interest.

s 81 relates to compensation to owners.

The holder of a petroleum interest (permittee) must pay to, the owner of land of a petroleum interest and any occupier of land comprised in the petroleum interest who has a registered interest Compensation is for:

(a) deprivation of use or enjoyment of the land, including improvements on the land; and

(b) damage, caused by the permittee or licensee, to the land or improvements on the land.

A permittee shall not commence exploration operations unless notice is given to:

(a) the owner of land comprised in the exploration permit and any occupier of the land who has a registered interest in that land of the proposed date of commencement, nature and duration of the permittee's exploration operations and served those persons with a copy of the relevant *Petroleum Act* sections, and

(b) advised the Minister that he has complied with paragraph (a).

Maximum penalty:

If the offender is a natural person – 400 penalty units or imprisonment for 2 years.

If the offender is a body corporate – 2 000 penalty units.

Where a permittee or licensee and a person entitled to compensation are unable to agree upon an amount or other benefit, by way of compensation, either party may refer the dispute to the Tribunal (being the NT Civil Administration Tribunal).

An agreement in relation to compensation may include compensation for work undertaken under an exploration permit, retention licence or production licence or under all exploration permits and licences held by the permittee or licensee in relation to that land.

Section 82, registered interest, in relation to land, means an interest registered on the Register kept by the Registrar-General under Part 3 of the Land Title Act.

Section 83 Conditions about compensation for effect on native title.

Permits relating to Native Title affected land require a Tripartite and Ancillary Agreement between Land Councils/Native title claimants and permit holders. No title will be granted unless such an agreement has been signed.

An ancillary agreement includes all compensation and considerations. The Northern Territory Government is not a party to the ancillary agreement. It is, therefore, the responsibility of the Land Councils and claimants to ensure Native Title interests are adequately compensated.

Where there are no Native Title claimants the Central Land Council may still insist on a compensation agreement over permit areas of Native Title affected land, although not required by legislation.

Agreements may cover exploration activities under an Exploration Permit and may extend through to production activities. However, this is a matter for negotiation between the parties.

Sections 73, 74 and 77 of the Act provide powers to rehabilitate and make good of property.

The permittee and licence holders must comply with a range of conditions before they surrender a permit or licence or before a permit or licence is cancelled.

Section 73 - A permittee or licence holder must have complied with all conditions and directions.

Section 74 – The Minister may commence cancellation of a permit or licence if conditions or directions have not been complied with.

Section 77 – Provides for the Minister to direct the permittee or licensee to:

(a) remove or cause to be removed from the former exploration permit or licence area, property brought into that area by any person engaged or concerned in operations authorised by the exploration permit or licence, or to make other arrangements in relation to the property satisfactory to the Minister;

(b) to plug or close off all wells drilled or bored in the former exploration permit or licence area; and

(c) to restore the surface of the former exploration permit or licence area, where disturbed, and take measures to rehabilitate the area, to the satisfaction of the Minister.

A person shall comply with a direction under s77(1)

Maximum penalty,

if the offender is a natural person – 500 penalty units,

if the offender is a body corporate – 2 500 penalty units.

One penalty unit currently is A$154.

14. Strategic development

Question

The Inquiry has received submissions to the effect that landholders, regional communities and the industry regulator in Queensland were not prepared for the fast and intense development of the coal seam gas industry in that State.

Since the "invasion" (as some stakeholders have described it) of the coal seam gas industry in Queensland in 2010, the Queensland government has, among other things:

- introduced and subsequently updated a Land Access Code under the Mineral and Energy Resources (Common Provisions) Act 2014 (Qld);
- established the GasFields Commission Queensland as an independent statutory body to, among other things, facilitate better relationships between landholders, regional communities and the onshore gas industry;
- introduced a Bill for the establishment of a Land Access Ombudsman, which is intended to be an independent body to help landholders and gas companies resolved alleged breached of land access agreements;
- established the Office of Groundwater Impact Assessment, which is an independent statutory body to support the management of groundwater impacts from petroleum and gas development; and
- developed a Gas Action Plan, which the Inquiry understands will be released shortly.

The mechanisms listed above were introduced after development of the industry commenced. The Inquiry has received submissions that the coal seam gas industry may have been in a better position to earn and maintain a social licence to operate had some, or all, of the measures listed above been in place prior to the coal seam gas "boom".

The Inquiry seeks DPIR's comment on this statement. Please describe any measures, including the measures adopted in Queensland, or in any other jurisdiction (whether subject to a moratorium on hydraulic fracturing or not, and including overseas jurisdictions, for example, Alberta, Canada), that DPIR considers may restore the community's trust in the regulator and provide a foundation upon which the industry can earn a social licence.

Finally, please describe the mechanisms that are available under the current regulatory framework to ensure the strategic development of the shale gas industry. Specifically, please advise whether the current regulatory framework can accommodate the consecutive or staged (as opposed to concurrent) development of shale gas reservoirs.

The panel suggests that a number of measures were taken in Queensland that if implemented earlier may have assisted industry in earning a more robust "social licence to operate":

- The introduction of a Land Access Code;
- Establishment of the Gasfields Commission;
- Introducing a Bill to establish a Land Access Ombudsman;
- Establishing the Office of Groundwater Impact Assessment; and
- The development of a Gas Action Plan

Another possible inclusion is the Gas Industry Social and Environment Research Alliance[8] (GISERA), a collaboration between CSIRO, industry and the Commonwealth and state governments, established to undertake publicly-reported independent research. The purpose

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[8] https://gisera.org.au/

of GISERA is to provide quality assured scientific research and information to communities living in gas development regions focusing on social and environmental topics including groundwater and surface water, biodiversity, land management, the marine environment, human health impacts and socio-economic impacts.

The governance structure for GISERA is designed to provide for and protect research independence and transparency of research. It is possible that GISERA could be operationalised in the NT to inform policy and decision-making about the gas industry in the NT.

In terms of the Queensland experience, three liquefied natural gas (LNG) projects were approved in quick succession, all with start-up dates very close together in 2014 and 2015. All three projects planned to export Queensland's coal seam gas resources (CSG) making this a world first for CSG to LNG developments. While there could be similarities with shale gas development in the Northern Territory, some of the key differences in the development of the resource include:

- The production profile for a coal seam gas well differs from conventional and shale gas wells in that the coal must be dewatered prior to increased gas production requiring fewer wells to be drilled up front in a shale gas development.
- Shale gas wells will have higher production capacity and a higher expected ultimate recovery than coal seam gas wells.
- Shale gas wells can be co-located on a single well pad, thereby minimising surface footprint.

Industry in the Northern Territory is not likely to be subject to the same development time pressures that Queensland experienced. The substantial volumes of gas required to meet the timeframes for the three LNG projects accelerated the development of the coal seam gas industry. In addition, there are some unique aspects to the Northern Territory compared to other jurisdictions that the panel should take into consideration, which include:

- The only jurisdiction subject the Aboriginal Land Rights Act (approx. 50% of the NT).
- There is very little freehold land in the Northern Territory (1-2%).
- The highest proportional population of Aboriginal people in all of Australia.
- Extremely sparsely populated with an overall population of 245,000 of which 30 percent identify as Aboriginal people (compared to 3% in the rest of Australia) and of which more than 85 percent live in either Darwin (59%), Katherine (9%) or Alice Springs (17%). Only 6 percent live in Arnhem Land and 9% in other remote communities.
- The Territory has a workforce of 140,000 people up from 35,000 in 2007.
- Pastoral leases in the Northern Territory comprise very large acreage.
- Consequently, the number of pastoral landholders is significantly lower than in for example Queensland.
- Exploration Permits in the Northern Territory comprise very large acreage, hence one title holder has rights to vast tracts of land (which may comprise several traditional owner groups and pastoralists).
- Much of the Northern Territory is under a petroleum Exploration Permit or under application for an Exploration Permit.
- Exploration permits may contain up to 200 blocks each around 80 km^2 in size.

- The NT has a tropical climate in the North and an arid climate below the Tropic of Capricorn.
- Water is scarce in some areas which are declared water control districts but water resources are robust in other areas.
- The NT has a long history of resource development.
- Darwin is close to hosting three LNG trains (DLNG and Ichthys) and will soon provide operational support to four LNG (including Prelude LNG).
- Infrastructure (roads, rail, pipelines etc.) is limited.
- Much of the NT remains under explored particularly for petroleum.
- It is now well established that the Beetaloo Sub-Basin has significant potential for shale gas development, subject to economic viability.
- Shale gas can be developed with a substantially smaller footprint than coal seam gas due to higher production per well and co-location of wells on multi-well pads.

Of interest, Norway accumulated the largest sovereign wealth fund by investing royalties from Norway's successful oil and gas industry in an Oil Fund[9] (Oljefund). A well-managed sovereign wealth fund provides intergenerational equity by ensuring the proceeds from natural resource development benefit citizens for generations to come. A similar measure may change perceptions of short-term gains from the industry and build support with Territorians that wish for a sustainable future.

There is strong support for taking a strategic approach to shale gas development. This will require a collaboration between relevant government agencies, industry, land councils, local government and other interested stakeholders. Given the NT's unique circumstances, the shale gas industry in the Northern Territory would evolve differently to the Queensland experience and with projections that first commercial gas will be some 5-10 years away, a strategic planning process could be initiated and implemented progressively.

15. Reference materials

Question
Please identify any reference materials that the Inquiry should consider that are not referenced in the Interim Report.

Well integrity

King and King 2013, Environmental risk arising from well construction failure – differences between barrier and well failure and estimates of failure frequency across common well types, locations and age (SPE166142)

Van der Kuip et al. 2011, High-level integrity assessment of abandoned wells

Walker et al. 2014, Methodologies for Investigating Gas in Water Bores and Links to Coal Seam Gas Development (CSIRO)

Economic development

ACIL Allen 2017, An economic impact analysis of the Ichtys LNG Project

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[9] https://en.wikipedia.org/wiki/Government_Pension_Fund_of_Norway

Queensland Gasfields Commission 2017, On new ground - Lessons from development of the world's first export coal seam gas industry

Northern Territory Government 2017, Economic development framework

Deloitte Access Economics 215, Economic impact of shale and tight gas development in the NT

Greenhouse-gas emissions

Day et al. 2014, Field measurements of fugitive emissions from equipment and well casings in Australian coal seam gas production facilities (CSIRO)

Day et al. 2017, Methane emissions from CSG well completion activities (CSIRO)

Australian Government Department of the Environment and Energy 2017, Update on recent empirical evidence on fugitive emissions from the gas industry

Regulatory

Australian Government 2014, Regulator performance framework

Australian Government 2014, Guide to regulation

Australian Government Department of Industry Innovation and Science 2016, Best Practice Guide to Using Standards and Risk Assessments in Policy and Regulation

Australian Government 2013, Best practice regulation handbook

Australian Government Department of Industry 2014, Industry officers guide to regulation reform

Australian Government Department of Prime Minister and Cabinet – Office of Best Practice Regulation 2014, The Australian Government Guide to Regulation

Australian National Audit Office 2014, Administering regulation –achieving the right balance

Government of Western Australia 2015, A guide to the regulatory framework for shale and tight gas in Western Australia, a whole of government approach

Productivity commission research report 2009, Review of the regulatory burden on the upstream petroleum (oil and gas) sector

Productivity commission inquiry report 2013, Minerals and energy resource exploration

State Review of Oil and Natural Gas Environmental Regulations (STRONGER) 2015, Guidelines

Colorado Department of Natural Resources Oil and Gas Conservation commission 2014, Risk-based inspections - strategies to address environmental risk associated with oil and gas operations

Elsner et al. 2015, Comment on the German Draft Legislation on Hydraulic Fracturing: The Need for an Accurate State of Knowledge and for Independent Scientific Research

European Commission 2013, Regulatory provisions governing key aspects of unconventional gas extraction in selected Member States - final report

Social licence

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I trust that you will find the information provided comprehensive and useful. Should you require any further information please do not hesitate to contact the department through Deputy Chief Executive, Rod Applegate.

Yours sincerely

Alister Trier
Chief Executive

23 August 2017