Imperial Oil & Gas

EP 187

Appendix 13

Methane Emissions Management Plan

IMP 5-1

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1 Introduction

1.1 Background

Section D.5.1.2 of the *Code of Practice: Onshore Petroleum Activities in the Northern Territory* (2019) (*the Code*) provides mandatory requirements to be addressed in the development of a Methane Emissions Management Plan (MEMP). This plan has been developed to comply with *the Code* and forms part of this Imperial EP 187 Carpentaria Pilot Project (CPP) EMP.

1.2 Aim

This MEMP aims to reduce fugitive methane emissions from the Activity to ALARP and acceptable through efficient and comprehensive operational practices, monitoring, and management.

1.3 Purpose

The purpose of this plan is to detail how fugitive methane emissions from the Activity will be reduced to as low as reasonably practicable (ALARP) and acceptable. This plan provides a focused and systematic approach to controlling and reducing fugitive emissions.

1.4 Scope

This plan applies to all aspects of the Activity where fugitive emissions of methane could occur.

2 Activity Description

The Activity is described in detail in **Section 3** of the EMP.

3 Greenhouse Gas Emissions – Large Emitters

In September 2021, the NT Government implemented its *Greenhouse Gas Emissions Management for New and Expanding Large Emitters*, [Northern Territory Government, 2021] setting standards for managing greenhouse gas emissions in new or expanding industrial projects.

As part of the Northern Territory's commitment to achieving net-zero emissions by 2050, projects that trigger assessment criteria outlined in the policy must prepare a Greenhouse Gas Abatement Plan.

The guide under the policy for identifying large industrial project is a threshold of;

- Estimated scope 1 emissions (Greenhouse gases directly emitted to atmosphere by an activity) of 100,000 tCO_2-e in any financial year over the life cycle of a project, not counting emissions generated from land clearing directly associated with the project.

Large industrial projects that exceed the threshold must develop and implement a greenhouse gas abatement plan (GGAP) that has been tailored specifically for their project. A project's GGAP should be submitted for assessment as part of the usual process for a project to obtain an environmental authorisation.

Imperial will apply to the Minister for approval to recover petroleum on an appraisal basis under Section 57AAA of the *Petroleum Act 1984 (NT)*. If successful, this will enable Imperial to conduct production appraisal tests without significant flaring.

Excluding flaring of gas to be exported to the MRGP, the average annual GHG estimated emissions from the Activity are approximately 30,000 tCO_2-e over the period covered by the EMP. In no financial year covered by the EMP do the estimated emissions exceed the 'large greenhouse gas emitters' Industrial project annual threshold of 100 000 tCO_2-e [NT EPA, 2022].

4 Regional Methane Monitoring

4.1 Baseline Methane Assessment

Section D.4.1 of *the Code* sets out the requirements for regional methane baseline assessment and ongoing monitoring. These assessments are conducted by or on behalf of the Northern Territory Government, funded by industry, and are required to be designed and implemented by a suitably qualified and experienced professional who is approved by the Minister.

The *Methane and Greenhouse Gas Studies for the Beetaloo Sub-basin Strategic Regional Environmental and Baseline Assessment* (*the Methane Study*) aimed to establish the greenhouse gas baseline for the Beetaloo Sub-basin [CINDY ONG et al., 2022].

The *Methane Study* also establishes reference sites and a program for ongoing monitoring to address the requirements described in the final report of the *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory* (*the Inquiry*) and therefore has been accepted as satisfying Section 4.1 of *the Code* [A. ANDERSON et al., 2018].

4.2 Regional Methane Assessment Program

A Regional Methane Assessment Programme, described in Section D.4.2 of *the Code*, is conducted to characterise the existing natural and anthropogenic sources of methane emissions across each permit or licence area and adjacent areas, before the commencement of exploration activity, and immediately after the commencement of full-scale production.

The *Methane Study* included an estimation of the emission rates of the current main sources of emissions based on best available estimation factors and/or models developed by NT and national government programs and researchers and has therefore been accepted as satisfying Section D.4.2 of *the Code*.

4.3 Routine Periodic Atmospheric Monitoring Programs

Routine Periodic Atmospheric Monitoring Program, described in Section D.4.3 of *the Code*, are conducted to provide for periodic monitoring, so that any changes in methane emissions can be detected during the life of a project that has entered the production phase. These assessments use the Regional Methane Assessment Programmes as their baseline.

As part of the *Methane Study*, series of mobile surveys were conducted from October 2021 to June 2022. The findings included:

- The difference in the background concentration measured within the Beetaloo study area in different seasons is in line with the national reference trend in Australia.
- The main sources of elevated methane concentrations detected during the surveys were cattle, fires, and towns/fuel stations.

The *Methane Study* has been accepted as satisfying the requirements of Section D4.3 of *the Code*.

5 Methane Sources, Controls and Standards

5.1 Potential Sources and Controls

Certain aspects of the Activity may give rise to methane emissions. These aspects and the controls to limit methane emissions are described in **Table 5—1**.

Table 5—1 Emission Descriptions and Controls

Aspect	Emission Description	Controls
Drilling of Petroleum Wells	• Shale formations have negligible permeability with a limited influx of gas from target formations. Methane is not expected to be encountered. If any is found, emissions are expected to be small (<1 tonne) and restricted to outgassing of hydrocarbon within intersected geological formations brought to the surface.	• While drilling, the well is kept overbalanced (well pressure maintained above formation pressure) to prevent gas influx from geological formations into the wellbore.
Operation of Petroleum Wells - Stimulation	• The completed well is unloaded to allow hydrocarbons and fluid to flow to the surface. • All fluids, sand and hydrocarbons from the well will initially flow to an atmospheric pressure open separator. The change from atmospheric pressure separator to low pressure separator is to reduce emissions. The flow to the atmospheric separator will likely be vented as flaring is not currently practicable, however this will be for a short duration when the well is not producing significant gas volumes, so only releases a small amount of gas into the atmosphere from flowback fluid. Once the flow is diverted into the low-pressure separator the gas will be sent to the CGP. • If the well is brought online before the CGP is commissioned it is likely that the well will be cleaned up to a local flare for a minimal period. In this case the flow would be diverted via the separator to the local flare instead of the CGP.	• The well will be kept overbalanced to prevent gas influx during and after stimulation. • Stimulation fluids are kept within the formation after each stage (until flowback). • Personal Gas Detectors (PGD) used on-site where signed or inductions require. Should a methane leak be identified by PGD monitoring, leak classification, remediation and notification requirements as described in the MEMP will be implemented.
Ongoing Well Operations/ Suspension	• During post stimulation operations, methane emissions are restricted to unplanned leaks from wellheads or well pad facilities including surface casing vents.	• Wells completed with multiple barriers in accordance with the approved WOMP. • Well maintenance to be detailed in the approved WOMP. • Wellhead pressure monitoring. • PGD used to check high point vents, flanges, and valves. • Wellheads are designed per the *NT Code of Practice* and API standards to minimise loss of methane containment [DENR, 2019]. • PGD used on-site where signed or inductions require. Should a methane leak be identified by PGD monitoring, leak classification, remediation and notification requirements as described in the MEMP will be implemented. • Routine wellhead maintenance, in accordance with the well Integrity Management System, will be carried out. • Wells are designed and constructed to be gas tight with multiple barriers to flow. • Each well and equipment on a well pad will be inspected every six months for leaks using a United States Environmental Protection Agency (US EPA) Method 21 [United States Environmental Protection Agency, 2017] compliant monitoring device. • Remotely controlled shutdown valves exist on all wells operated in the case of a leak event or process upset.

Aspect	Emission Description	Controls
Carpentaria Gas Plant (CGP)	• Methane emissions at the CGP are restricted to unplanned leaks such as upset conditions or though leaks in fittings.	• Plant and equipment operated and maintained by qualified personnel. • CGP will have a flare system to flare gas from process upsets. • Construction of plant includes leak testing at all leak points and pressure testing of the facility. • 24-hour monitoring of Gas Plant and emergency alarm system. • PGD used on-site where signed or inductions require. Should a methane leak be identified by PGD monitoring, leak classification, remediation and notification requirements as described in the MEMP will be implemented. • Plant designed and installed to Australian standards including HAZOP assessments, leak testing, pressure testing, and appropriate commissioning.
Gas Gathering Flowline Network	• Methane emissions at the flowlines are restricted to unplanned leaks such as upset conditions or though leaks in fittings.	• Automatic over-pressure control on flowlines. • Flowline pressure monitoring. • Flowlines designed, installed, and operated in accordance with Australian Pipelines and Gas Association (APGA) Code of Practice for Upstream Polyethylene Gathering Networks, 2019 (PEGN Code) [APGA, 2019]. • PGD used to check high point vents, flanges, pneumatic controllers, and valves. • PGD used on-site where signed or inductions require. Should a methane leak be identified by PGD monitoring, leak classification, remediation and notification requirements as described in the MEMP will be implemented. • Plant and equipment operated and maintained by qualified personnel. • Flowlines will be inspected weekly by visual inspection of the High Point Valves (HPV).

5.2 Applicable Standards

Industry standards and codes that relate to the minimisation of methane emissions are listed in **Table 5—2**.

Table 5—2 ISO/API Standards for Material Selection

Component	Applicable Standards
Casing	• ISO 11960: Steel pipes for use as casing or tubing for wells. • API Specifications 5CT - Casing and Tubing.
Couplings	• ISO 13679 Procedures for testing casing and tubing connections.
Cement and Additives	• American Petroleum Institute Recommended Practice, (API RP) 10B-2 Recommended Practice for Testing Well Cements.
Drilling Fluids	• ISO 10414-1: Recommended Practice for the Field-Testing Water Based Drilling Fluids. • American Petroleum Institute (API) 13B-1 and 13B-2 Recommended Practices.
Well Control Equipment	• API STD 53: Blow-Out Prevention Equipment Systems for Drilling Wells. • API 16A (ISO 13533): Specification for drill-through equipment. • API 16D: Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment.
Wellheads	• API 6A: Specification for wellhead and Christmas tree equipment. • ISO 10423: Petroleum and Natural Gas Industries – Drilling and Production Equipment – Wellhead and Christmas Tree Equipment.

Well maintenance will be conducted following the Well Operations Management Plan (WOMP).

6 Monitoring Methodology and Frequency

6.1 Inspection and Monitoring Frequency

Section D.5.2.2 of *the Code* outlines the mandatory requirements for inspection procedures and frequency to detect methane emissions from the Activity.

To ensure fugitive emissions are managed accordingly:

(a) Regular visits will be made to operational well sites, gathering systems and processing facilities in accordance with this MEMP.

(b) PGD used on-site where signed or inductions require. Should a methane leak be identified by PGD monitoring, leak classification, remediation and notification requirements as described in the MEMP will be implemented.

(c) All persons completing emission detection activities will be properly trained and competency assured.

(d) Leak inspections will be conducted on the minimum frequencies detailed in **Table 6—1**.

(e) Leak inspections of individual operating plant will be undertaken at an increased frequency as determined by the risk assessment and in consideration of previous audit/inspection findings for those specific facilities; and

(f) Where the operator uses optical gas imaging for leak detection, an annual inspection using US EPA Method 21 will also be performed on the facility.

Table 6—1 Inspection Minimum Frequency

Facility or System	Operator Leak Detection
Above ground facility – petroleum well pad equipment	• 6 monthly
Low pressure pipeline and fittings	• Annually
Steel or high-pressure pipelines	• Annually
Compressor stations and pneumatic devices	• Quarterly
Processing plant	• Annually
All gas containing equipment following major maintenance (e.g., repacking, replacement of seals)	• Within 48hrs of recommissioning.

*Table 10 of *the Code*

Note: if inspections are conducted using Optical Gas Imaging, an annual inspection using US EPA Method 21 must also be performed on the facility.

6.2 Standard Leak Detection Instruments

Instrument selection and operation will be selected to ensure that they are fit for purpose and maximise the probability of detecting methane leaks.

Section D.5.3.2 of *the Code* details the mandatory requirements for leak detection methods:

(b) Leak testing will be conducted using either:

  i. USEPA Method 21; or

  ii. Optical gas imaging (OGI).

(c) [No other superior method is currently proposed].

(d) All gas leak surveys will be conducted by suitably qualified personnel using appropriate gas detection instruments calibrated in accordance with the manufacturer's requirements.

(e) Gas detectors will be maintained and tested in accordance with manufacturer's instructions.

(f) If USEPA Method 21 is used, the gas detection instruments, operation and calibration procedures defined in USEPA Method 21 will be followed.

(g) If OGI is used for leak detection, the instrument will be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm (by volume) at a flow rate of $\leq$ 60 g/hr from a quarter inch (6.4 mm) diameter orifice.

6.3 Leak Detection Methodology

All gas leak detection will be conducted by suitably qualified personnel using appropriate gas detection instruments calibrated and maintained following the manufacturer's requirements.

Leak testing will be undertaken using the United States Environmental Protection Agency (US EPA) *Method 21* [US EPA, 2017] or optical gas imaging (OGI), in accordance with Section D5.2 of *the Code*.

Method 21 or OGI inspections require access to the equipment's surface and are extremely effective at pinpointing leaks [United States Environmental Protection Agency, 2017].

The following procedures will be followed when conducting Method 21 inspections:

1. Ensure gas detector is calibrated and functioning properly.
2. Ensure the appropriate permitting is obtained before entry into a hazardous area.
3. Place the probe inlet at the surface of the component interface where leakage could occur.
4. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where the leakage is indicated until the maximum meter reading is obtained.
5. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time (i.e., at least a minute).
6. If the maximum observed meter reading is greater than 500 ppm at the surface of a piece of infrastructure, the leak will be measured again at 150 mm immediately above (and downwind) of the leak in an open-air environment.
7. The leak will be classified as described in **Section 7** of this MEMP.
8. The location of the leak will be documented and photographed (if it is safe to do so).
9. Any liquid petroleum leaks will also be identified, including estimates of leak rate and the volume released.

If leak detection is conducted using Optical Gas Imaging, a Method 21 detection survey must be done at least once annually.

7 Leak Classification

Leaks will be classified in accordance with Section D5.5 of *the Code*.

7.1 Minor Leak

Section D.5.5.1 of *the Code* defines a minor leak as a leak that:

(a) Originates from an above ground source.

(b) Is an unplanned release.

(c) Yields a methane concentration of 500 ppm (by volume) to 5,000 ppm (by volume) when measured at the surface of the component according to USEPA Method 21; or

(d) Any emission visible with an OGI instrument.

Leaks identified during commissioning or bringing equipment back into service are not classified as minor leaks, however they should still be recorded and reported where required under other frameworks (such as federal legislation or the incident reporting framework of Part 3 of the PERs).

7.2 Significant Leak

Section D.5.2.2 defines a significant leak as a leak that originates from above ground facilities, gathering systems and subsurface pipelines that meets one of the following criteria:

(a) A leak due to an unplanned release from an above ground petroleum facility that, when measured at the surface of the component according to USEPA Method 21; gives a sustained Lower Explosive Limit (LEL) reading greater than 10% (5,000 ppm by volume) of the LEL.

(b) A leak due to an unplanned release from a gathering system - subsurface pipeline that, at ground level; gives a sustained reading greater than 500 ppm (by volume) for a 15 second duration.

(c) A liquid petroleum (condensate / oil) loss of containment that exceeds 200 litres of hydrocarbons.

When it is safe to measure leaks, leaks that are classified as significant leaks during commissioning or bringing equipment back into service will be recorded and reported as per Section D.5.6.2 of the Code.

Any identified leak that reports above the threshold level for reporting significant leaks, or if the leak is too large or not safe to measure, will be recorded and reported as per Section D.5.6.2 of *the Code*.

8 Leak Remediation and Notification

Section D.5.6 of *the Code* details the requirements for leak remediation and notifications.

8.1 Minor Leaks (D.5.6.1)

A minor leak is defined in Section D.5.5.1.(see Section 7.1 above)

(a) All minor leaks must be documented and repaired as soon as practicable, but in any event within 30 days of identification.

(b) In the event of the 30-day deadline being unachievable, the Minister must be notified within the 30 days and provided with the reason for the delay and a target date for completion of the work.

8.2 Significant Leaks (D.5.6.2)

A significant leak is defined in Section D.5.5.2. (See Section 7.2 above).

In the event that a significant leak is detected:

(a) *the safety management system requirements for risk assessment and emergency response must be followed.*

(b) *For all significant leaks,* Imperial's first priorities are as follows:

i. *an exclusion zone a must be established around the leak and appropriate restrictions on access to the exclusion zone must be imposed, along with any other necessary immediate* controls.

ii. *the leak shall be repaired or made safe as soon as practicable immediately after detection, as* follows.

a. *the gas leak must be isolated,* repaired, if possible, contained or otherwise made safe within 72 hours of detection of the leak.

b. *in the event of the 72-hour repair deadline being unachievable, the reason for the delay and a target date for completion of the work must* *be submitted to the Department of Primary Industry and Resources before the deadline passes; and*

c. *if it is contended that the risks of immediately repairing a leak exceed the risk posed by the leak, an extension of the 72-hour deadline may be sought if provided that other measures to mitigate the risk are undertaken (e.g. ensuring no ignition sources or personnel are permitted in the exclusion zone).*

iii. *complying with the other steps in this section D.5.6.2 must not compromise,* impair, or delay the operator's actions to immediately make the site safe and establish exclusion zones.

(c) *Imperial* must make the following notifications:

i. *appropriate notifications must be given to Northern Territory Government departments in compliance with any legislative requirements:*

a. *along with all other details required under relevant legislation, this notification must include the date of identification, nature and level of leak, operating plant site name,* number, and location as well as initial steps taken to minimise the risk; and

b. *in the case of an emergency situation, a notification to the Department of Primary Industry and Resources' emergency hotline number 1 300 935 250 must be made within 24* hours.

ii. *the* landowner or occupier of the property on which these leaks are occurring must be notified if the leak cannot be repaired immediately.

(d) *Remediation work must be conducted in accordance with the following:*

i. *Only commence work after a suitable risk assessment has been undertaken and relevant safety procedures are followed including consideration of all the required Personal Protective Equipment (PPE) and emergency response materials.*

ii. *For leaks identified on well equipment -higher order controls, such as* containment by repair, must be implemented wherever possible.

(e) *For leaks identified on gathering systems (where an excavation is necessary to effect repair) repairs must be completed as soon as reasonably practicable in consideration of the location of the site, safety to personnel and the public, potential environmental harm, likely access to the site from landholders or the general public, and landholder/community concerns in relation to the leak.*

(f) *For leaks identified on well casings or adjacent to the well casing (where a work over rig is necessary to effect repair) repairs must be completed as soon as reasonably practicable in consideration of the location of the well, safety to personnel and the public, potential environmental harm, likely access to the well from landholders or the general public, and landholder/community concerns in relation to the leak.*

(g) *A written close-out report must be submitted within 5 business days of the remediation of the leak, specifying the date of* identification, nature and level of leak, location and name of the operating plant, and the rectification actions taken.

(h) *If finalising the remediation is delayed more than 7 business days from the identification of the leak an update must be submitted on that day. The final close out report shall be provided when all work is completed.*

(i) *Full cooperation with relevant regulators is required.*

9 Compressors and Pneumatic Devices

Section D.5.7.2 of *the Code* details the requirements to ensure that compressors and pneumatic devices are designed, selected, and operated to minimise or eliminate fugitive emissions.

Emissions from compressors and pneumatic devices must be reduced through compliance with the following requirements:

(a) missions from new, modified, or reconstructed wet seal centrifugal compressors (except for those located at well sites) must be captured and routed to a control device;

(b) the rod packing on each new, modified, or reconstructed reciprocating compressors must meet one of the following:

i. it is changed on or before 26,000 hours of operation; and

ii. it is changed on or before every 36 calendar months; or

iii. it routes all emissions through a closed vent system under negative pressure.

(c) The use of pneumatic controllers on new, modified, or reconstructed infrastructure must comply with the following requirements:

i. for gas processing facilities and compressors they must be driven by instrument air systems with a zero natural gas emissions

ii. for other infrastructure, and where low-bleed pneumatic controllers are used, they must have a natural gas bleed rate no greater than 0.17 m3 h-1 (6 scf/h)

(d) The use of pneumatic pumps must comply with the following requirements:

i. for gas processing facilities and compressors they must be driven by instrument air systems with a zero natural gas emissions.

ii. for well sites, pneumatic pump emissions must be routed to a control device that must achieve greater than 95 % emission reduction.

iii. for existing well sites, which have been modified or reconstructed, it is permissible to direct emissions to an existing control which achieves less than 95% emissions reduction where it is able to be demonstrated that the environmental risks associated with this have been reduced to ALARP and acceptable.

10 Venting and Flaring

Imperial will apply to the Minister for approval to recover petroleum on an appraisal basis under Section 57AAA of the Petroleum Act 1984 (NT). If successful, this will enable Imperial to conduct production appraisal tests without significant flaring.

Section D.5.9 of *the Code* details the requirements to ensure that venting and flaring of natural gas is eliminated or minimised where practicable.

10.1 Well Related Activities Mandatory Requirements (D.5.9.2)

(a) For well construction activities Reduced Emissions Completions (REC) should be employed where technically feasible so that gas is captured for sale or other use.

(b) Where REC are not practicable:

   i. flaring should be used rather than venting; and

   ii. venting should only be used where capture or flaring is not possible.

(c) Emissions from exploration, well construction (including during flowback) and workovers must be measured, and reports submitted. These emissions should be measured using methods consistent those specified under the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Other methods may be used if approved in an EMP.

10.2 Gas Processing Activities Mandatory Requirements (D.5.9.3)

Where natural gas is vented or flared at a gas processing or other downstream facility, emissions must be estimated and reported. Methods used for this purpose must be consistent with the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Other methods may be used if approved in an EMP.

11 Other Fugitive Emission Sources (D.5.9.4 of the Code)

In addition to leaks, venting and flaring considered in the preceding section of this MEMP, methane may also be released in significant quantities during certain planned and unplanned operations. These include some maintenance operations were gas in pipelines or other equipment is blown down, system upsets or accidental releases. Such emissions must be estimated using methods consistent with the National Greenhouse and Energy Reporting (Measurement) Determination 2008. Other methods may be used if approved in an EMP.

12 Annual Reporting

12.1 Northern Territory

Section D.6.2 of *the Code* details the mandatory requirements for government reporting.

Imperial will provide an annual report to the Northern Territory Government summarising the following:

- The records of the stages of flowback activities, including:
    - The date and time of the onset of flowback.
    - The date and time of each attempt to route flowback fluid to the separator.
    - The date and time of each occurrence in which the operator reverted to the initial flowback stage.
    - The date and time of well shut-in or connected into adjacent gathering lines.
    - The date and time that temporary flowback equipment is disconnected.
    - The total duration of venting, combustion and flaring over the flowback period.
- The results of leak detection surveys, outlining:
    - The extent of compliance with the leak management plan.
    - A summary of monitoring undertaken during the period.
    - A summary of minor and significant leaks identified during the reporting period including the following:

        - The date of identification and
        - Repair for each leak and those leaks that could not be repaired.
    - An explanation as to why any component could not be repaired and what actions will be taken to either decommission the component or otherwise remedy the problem.

- Imperial's reporting will be in accordance with *Section D.5.6* of *the Code* - Leak Remediation and Notification, and the emissions as described in *Section D.5.9* of *the Code* - Venting and Flaring will be consistent with the reporting requirements of the Clean Energy Regulator (Commonwealth) and will be provided separately to the Northern Territory Government in accordance with *the Code*.

- If the Activity is below the reporting threshold specified by the Commonwealth National Greenhouse and Energy Reporting Act (2007), emissions will still be reported for the approved regulated activities in this EMP to the Northern Territory Government under *the Code*.

12.2 Commonwealth

Imperial will estimate and report all greenhouse gas emissions in accordance with the requirements of the Clean Energy Regulator and the National Greenhouse Energy Reporting Act (CTH) as required.

13 References

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