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1 Access Track Construction

1.1 Overview

Eight-metre-wide access tracks will be constructed, as required, to provide access to well pads, campsites, gravel pits or water bores, compressor station, water treatment facility, etc. Where practicable, existing access tracks will be utilised. Where new access tracks are required, they will follow the disturbance footprint of the seismic survey or existing disturbed areas where practicable. The construction of access tracks will require vegetation clearing and rootstock removal, including areas within riparian zones. Where this is required, the path of least impact will be selected within the working corridor. Access tracks will be increased to a maximum width of 15m at intersections to provide vehicles with a safe turning radius and visibility. If road sections require a wear surface, where practicable, the material will be sourced from local quarries and turn out drains constructed; these drains will avoid mature trees.

The impact to trees of significance, or environmentally sensitive flora or fauna, will be minimised as practicable during the proposed program. A decision tree for tree clearing, when constructing linear infrastructure i.e., access tracks and flowlines, is shown in Figure 1.

1.2 Methodology

Timber and vegetation will be cleared from the access track alignment and stockpiled for future rehabilitation activities. To avoid further clearing, cleared timber and vegetation will be stockpiled in a naturally occurring clear area, where one is available in the immediate vicinity.

The access track will be formed and compacted using on-site materials; where local materials are unsuitable, additional materials will be imported, e.g., watercourse crossings.

An indicative access track and right of way section is shown in Figure 2.

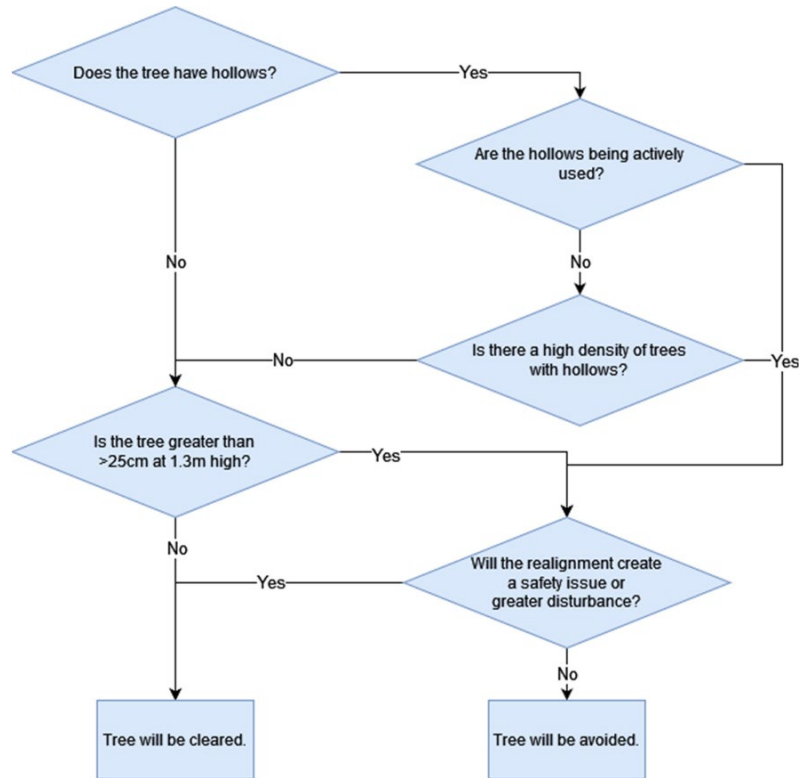


Figure 1: Tree Clearing Decision Tree for Infrastructure Construction

2 Flowline Construction, Operation, and Decommissioning

2.1 Overview

To provide safe and efficient transfer of high volumes of fluids between well pads, at low pressure ($\leq 1,500$ kPag) Polyethylene (PE) flowlines wastewater gathering network may be installed.

Fluids transferred in the Gathering Network may include:

- Groundwater.
- Drilling fluids.
- Flowback fluids.
- Wastewater.
- Gas

Flowlines will be constructed, operated, maintained, and abandoned in line with the "*Code of Practice for Upstream PE Gathering Lines in the CSG Industry and Companion Papers*" [APGA, 2019] (hereafter referred to as *the PEGN Code*).

The motivation to install and operate the Wastewater Gathering Network is to:

- Reduce the land clearing requirements for storage tanks at each well site.
- Provide the capability for recycling and reuse of fluids between well sites.
- Optimise in-field flowback fluid and wastewater treatment to a centralised location.
- Reduce trucking requirements.
- Reduce the amount of wastewater for final disposal.
- Operate the well site to minimise the potential for contaminant releases to the environment and any potential impacts of such releases.

A gas gathering network will be installed to gathering gas from wellpads to the Carpentaria Pilot Project compressor station.

Imperial A will bury any flowlines outside of well pad fences to protect them from fire, flood, and damage from livestock and human activity; this is in line with industry best practice.

Flowlines will follow the disturbance footprint of access tracks, or other disturbed areas, to reduce the amount of land clearing required and allow efficient construction, operation, and maintenance.

2.2 Methodology

Flowline installation will be carried out utilising the following steps:

1. Right of Way (ROW) Clearing & Grubbing
2. Pipe Stringing
3. Pipe Jointing
4. Trenching and Bedding
5. Placing of Pipe into the Trench
6. Backfilling and Compaction
7. Pressure/Leak Testing
8. Pipe Survey, Location and Marker-Signposting
9. Commissioning
10. ROW Reinstatement

Further detail is provided in the following sections.

2.2.1 Right of Way Clearing & Grubbing

By following access tracks with Right of Way where practicable, clearing requirements will be reduced to widening existing access tracks by up to 8m, as opposed to clearing a dedicated 14m wide flowline route. Flowlines will be buried parallel to access tracks, avoiding above traffic flow, and enabling the current access track to be used as work areas. This arrangement will also allow for easy inspection of the ROW without a dedicated access track.

Timber, vegetation, and debris such as rocks etc., will be cleared and grubbed next to access track alignment for ROWs, and stockpiled on the edge of the ROW for future rehabilitation activities.

Before any ROW clearing is carried out in watercourses, the 7-day weather forecast will be checked to ensure an adequate window for the trenching, installation, backfill, and stabilisation works to be carried out.

2.2.2 Pipe Stringing

The pipe will be either stick (~12m lengths) or coils of up to 100m. The pipe will be strung out on the ROW when clearing and grubbing of each ROW section is complete. The pipe will not be strung across access tracks or watercourse crossings until it is ready for installation on the same day. When the pipe is strung from end to end, adequate topographic and geomorphic provision shall allow for unimpeded overland flow/drainage, access by property owners, fauna, and construction traffic.

2.2.3 Pipe Joining

PE pipe or fittings can be joined by heat fusion (welding) or mechanical fittings only. Adhesives, cement, or elastomeric joints are unable to be used in joining PE pipes and fittings for water applications in the oil and gas industry.

There are several types of heat fusion joints currently available, including butt fusion welding (butt welding), electrofusion welding, and saddle fusion welding. Saddle fusion welding is typically not used in the oil and gas industry.

Pipe joining is a skilled operation, which requires several very specific procedures to be performed to achieve a successful joint. Prior to construction, Imperial A will approve the service provider's joining procedures, and use data loggers verify conformance to the nominated welding parameters. Additionally, a unique weld numbering system will be established to identify each production weld, and tie-in for traceability records.

2.2.3.1 Butt Welding

The most widely used method for joining individual lengths of PE pipe is by heat fusion of the pipe butt ends, as illustrated in Figure 3.

This technique, which precludes the need for specially modified pipe ends or couplings, produces a permanent, economic, and flow-efficient connection. Welding parameters used will follow PIPA Guideline POP 003 [PIPA, 2018], which provides guidelines for butt fusion welding parameters. The welding temperatures for PE pipe used in constructing flowlines are not high enough to be considered a potential cause for ignition.



Figure 3: Standard Butt Fusion Join [APGA, 2019]

The following procedures will be adopted to ensure the integrity of the fusion welds:

1. The welding contractor shall have:
 - a. Demonstrated experience in fusion welding of PE pipe.
 - b. Suitably sized equipment which has been maintained in good condition with calibration status documentation available.
 - c. Qualified operators who have an up-to-date log detailing project and welding experience

2. Assessment of the proposed welding procedures:
 - a. Pre-qualified welding procedures for pipe class and diameters being proposed for the project and the welding machines or control box which will be used, and destructive weld testing data may be considered.
 - b. Carry out trial welds on the actual pipe to be used for the contract and have these destructively tested to meet the specified performance requirements (testing and minimum performance requirements are detailed in **Section 2.3.9 – Inspection and Testing**).
 - c. Determine and document the agreed welding parameters, procedures, and welding equipment (this may also include the use of welding tents, pipe end covers etc.); and
 - d. The agreed welding parameters, procedures and welding equipment become the contract requirements and should not be varied without additional evaluation and testing.
3. Determine quality control and assurance requirements, including but not limited to:
 - a. Inspection for wall thickness and welding zone preparation.
 - b. Internal inspection of pipe for obstruction and cleanliness. Including the removal of swarf after machining welding face for butt welding.
 - c. Maintaining a detailed welding log for each weld (including unique weld ID and GPS location record keeping).
 - d. Destructive testing of a percentage of welds.
 - e. Visual and non-destructive assessment of each weld.
4. Continuously review process and results.
 - a. Butt fusion welding is a skilled operation; several very specific procedures need to be carried out to achieve a successful joint. All operators carrying out butt fusion welding will be trained by appropriately registered training organisations (RTOs), meeting the prerequisite training requirements of PMBWELD 301.

2.2.3.2 Electrofusion Welding

The main difference between butt welding and electrofusion is how the heat is applied. The electrofusion joint is heated internally by a conductor at the joint interface. Heat is created as an electric current applied to the conductive material in the fitting. PE pipe to pipe connections made using the electrofusion process requires electrofusion couplings, as shown in Figure 4.

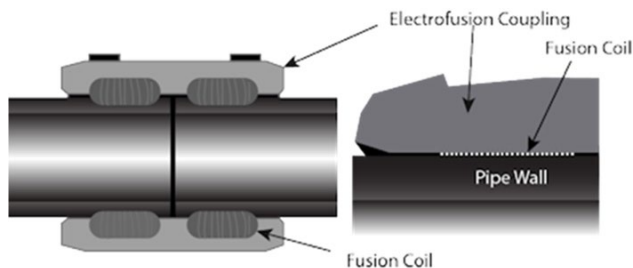


Figure 4: Typical Electrofusion Joint [PPI, 2023]

Electrofusion (EF) fittings shall conform to AS/NZS 4129 and be third-party certified by a JAS-ANZ accredited certifier under the StandardsMark, GasMark, WaterMark schemes, or equivalent.

To consistently make satisfactory electrofusion joints, it is essential to follow the jointing procedure, emphasising pipe surface preparation, cleanliness, joint restraint during the fusion and cooling cycles, and temperature control.

Electrofusion is a skilled operation; several specific procedures need to be carried out to achieve a successful joint. Imperial A will approve welding procedures before construction begins. All operators carrying out electrofusion welding will be trained by appropriate RTOs, meeting the prerequisite training requirements of PMBWELD 302.

2.2.3.3 Mechanical Joints

Where fusion joints are not appropriate, mechanical fittings can be used, particularly for the 50mm and smaller PE pipes. Three basic fittings can be used:

- Flanges.
- Mechanical compression joints.
- Mechanical couplings.

When jointing of PE pipe is required to other materials, a flanged joint is generally the most practical for field jointing. Otherwise, a material transition fitting can be considered and welded in.

Imperial A will preferentially use flanges for jointing to other materials.

2.2.3.4 Flanges

When jointing is required to other materials, a flanged joint is generally the most practical.

Jointing to other pipe materials may also be achieved using mechanical flange adaptors similar to mechanical couplers, except one end is replaced by a flange.

A typical flange connection is shown in Figure 5.

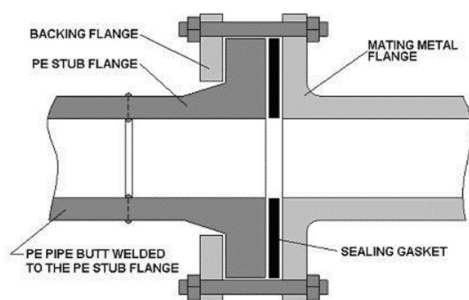


Figure 5: Typical Flanged Connection [APGA, 2019]

2.2.3.5 Mechanical Compression Joints

Mechanical compression joints will be installed following the manufacturer's requirements.

2.2.3.6 Mechanical Couplings

Mechanical couplings will be installed following the manufacturer's requirements.

2.2.4 Trenching and Bedding

A trench will be excavated to a depth that will give 750mm depth of cover (DOC) to flowlines installed, except where the flowline crosses an access track or watercourse, where it will have a DOC of no less than 1,200mm.

Trench excavation will be carried out using a trenching machine, excavator with an attachment, or similar. In both instances, the objective is to achieve a trench bottom free of rocks, stones or other material with an angular profile that may cause damage to the pipe and a trench profile in continuous contact with the pipe. When such conditions are achieved, the pipe will be laid directly on the trench bed; if this is not achievable from the direct trenching operations, bedding will be applied into the trench to achieve the same.

Any trenches that are left open overnight will be:

- Fenced with electric fencing to exclude livestock.
- Fitted with fauna ladders to allow fauna egress.
- Checked by a Fauna Spotter before starting works the next day, and any fauna removed.

No trenches across watercourses or access tracks will not be left open overnight.

Before any trenching is carried out in watercourses, Imperial A will check the 7-day weather forecast to ensure there is an adequate weather window for the trenching, installation, backfill, and stabilisation works to be carried out.

2.2.5 Placing of Pipe into the Trench

The pipe will be lowered into the trench without excessive strain and laid with sufficient slack to allow for contraction caused by temperature changes.

PE pipe up to approximately 160 mm diameter can usually be placed in the trench manually. Heavier larger diameter, pipe will require handling equipment to lift, move, and carefully lower the pipe into the trench.

2.2.6 Backing and Compaction

Following the laying of pipe, excavated material will be used to backfill the trench. Several quality assurance steps and processes will be used, including:

- The initial bedding material will be screened to ensure it is free of rocks, stones or other material with an angular profile that may cause damage to the pipe. The balance of the trench will be backfilled and compacted using excavated material.
- Compaction shall be performed to ensure the required compaction level is achieved while ensuring that any stress placed upon the pipe is acceptable.
- The standard of backfill and compaction shall minimise subsequent soil movement and prevent subsidence of the trenched area.
- The permeability of the backfilled and compacted trench shall be similar to that of the unexcavated material to minimise damage along the trench invert and potential 'tunnel' erosion.
- Where scouring could occur in a trench, barriers shall be installed to prevent scouring. Barriers shall be built of non-degradable foam, sandbags, or other approved material.

2.2.7 Pressure/Leak Testing

All new components of the flowline network and any part of an existing network that is diverted or altered in any way shall be subject to a pressure test to validate mechanical strength and detect leakage of the network before commissioning.

The PE Gathering Networks' pressure testing will be broken into two separate tests, a strength test, and a leak test. The strength test proves the pipe's integrity and identifies any large leaks or defects in the network being tested. The leak test determines if there are any small leaks in the network. The leak test shall be undertaken after the successful completion of a strength test. Further details on strength and leak testing are covered in Sections 2.3.9.8 and 2.3.9.9 respectively.

Due to the viscoelastic nature of PE, it is not practical to conduct such tests in a manner that ensures no pressure change. Variations of atmospheric pressure, the temperature of the test fluid in the pipe, and material creep significantly affect the test pressure. Therefore, it is necessary to permit some drop in measured pressure over the test period.

2.2.7.1 Pressure Test Safety

Pressure testing is considered one of the significant hazards in the development of a PE Network.

Pressure testing equipment will be fitted with regulators and Pressure Safety Valves (PSV) to ensure the Gathering Network is not over-pressured during testing. The primary safety control for pressure testing is QA/QC conformance, primarily in material selection and welding. The secondary safety control measure is the introduction and use of calculated exclusion zones.

2.2.7.2 Pressure Testing Exclusion Zones

The test section will have a defined primary exclusion zone, determined by the amount of stored energy released upon test section failure.

A secondary exclusion zone boundary shall be established around the control point.

Figure 6 shows the configuration of exclusion zones for pressure testing.

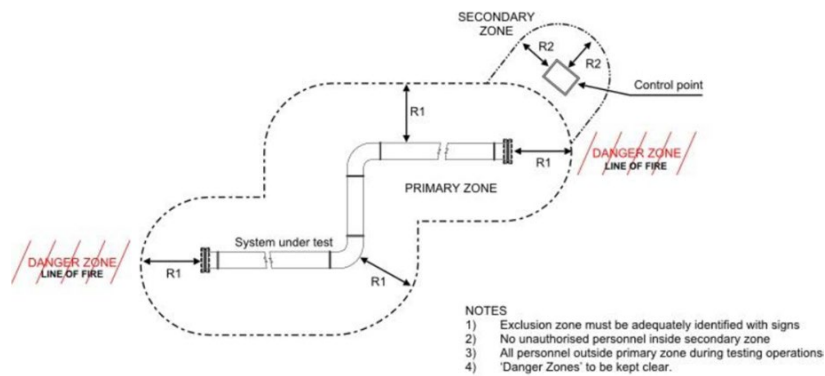


Figure 6: Defined Exclusion Zones [APGA, 2019]

2.2.7.3 Exclusion Zones During Pressure Tests

The primary exclusion zone is designed to achieve a specified distance from the test to the safe area for any unauthorised person to be located during the test.

While the test pressure is being introduced, and for the actual strength test period, strict precautions will be implemented to ensure that unauthorised persons are prevented from entering the exclusion zone (primary and secondary) test areas. Barriers, signs, or other markers shall be displayed to indicate the entry points to the restricted area. Consideration will be given to manning road crossings and other higher-risk locations while the test section is under test to ensure that no persons enter the test area.

After successfully completing the strength test, and after the pressure has been reduced to Maximum Allowable Operating Pressure (MAOP) or lower, authorised personnel may be allowed inside the primary exclusion zone.

The test equipment will be located outside the primary exclusion zone and be surrounded by a secondary exclusion zone. During testing operations, no unauthorised person will be permitted to enter this zone.

2.2.7.4 Pressure Testing Primary Exclusion Zone (R₁)

The primary exclusion zone boundary shall be calculated using the approach defined in ASME PCC-2 or following *Section 8.2.9 of the PEGN Code* requirements. This approach calculates the amount of stored energy and then calculates a distance based on the blast wave impact on personnel and structures. The minimum primary exclusion zone is:

- 30 m if the calculated energy is less than 135.5 MJ.
- 60 m if the calculated energy is between 135.5 and 271 MJ.

For energy levels greater than 271MJ, the distance $R_{scaled}(2TNT)^{1/3}$ in metres, calculated following *Appendix B2 of the PEGN Code*, based on a Rscaled number of 20, where TNT (Trinitrotoluene) is the energy measured in kilograms of TNT.

These distances are subject to an increase in the specific direction of failure to allow for potential projected missiles.

2.2.7.5 Pressure Testing Secondary Exclusion Zone (R₂)

The secondary exclusion zone boundary shall be established around the control point. The minimum recommended approach is to use the distance based on a scaled number of 20. In this calculation, the stored energy is the energy in the test equipment – hoses and headers. An alternative is to use an exclusion distance of 10 m.

2.2.7.6 Preliminary Testing

Sections of the network in key areas may need to be preliminary tested or pre-tested separate from the main network section. Examples are roads, creek crossings, and sections near plants and houses where the impact of a pressure test failure is critical. The fabricated pipe sections to be installed will be preliminary tested where possible. These sections can later be tied into a long test section. The preliminary section's exclusion zone can be reduced in these cases as it has previously passed a strength test.

2.2.7.7 Test Plan

A test plan will be developed for all pressure tests. This plan can be a generalised document covering most test cases. However, in all cases the particular risks and hazards associated with a test shall be understood and managed.

The test plan will be able to:

- Ensure that all risk controls are implemented.
- Ensure the completion of a Job Safety Analysis (JSA), and that all items identified are adhered to.
- Ensure that all relevant equipment has a current calibration certificate from a recognised and certified testing agency.
- Ensure that all measuring equipment is located at a suitable distance from the test section, to conform with exclusion zone requirements.
- Ensure that fluid and wastes disposal procedures outlined in the **EMP** are followed.

The person or persons responsible for the preparation of the test plan shall have appropriate qualifications and experience.

2.2.7.8 Strength Test

A strength test intends to confirm both a pipe 's integrity and identify any large leaks or defects in the network. If at the end of the test period, the test section's pressure is above MAOP and there is no evidence of a sudden pressure drop, then the test section will be considered to have passed. After completing the strength test, the pipe shall then be subject to a leak test process.

The criteria for pneumatic strength testing are shown in **Table 1**.

Table 1: Strength Test Criteria

Pneumatic Strength Test	Acceptance Criteria
<ul style="list-style-type: none"> • Starting pressure $fp \times MAOP$. • Test pressure to remain between $fp \times MAOP$ & $MAOP$ during the test. 	<ul style="list-style-type: none"> • Structural integrity maintained for 6 hours while pressure held between $fp \times MAOP$ & $MAOP$.

2.2.7.9 Leak Test

The leak test intends to identify any small leaks in the network. The 24-hour leak test shall be undertaken after a successfully completed strength test. The minimum starting test pressure shall be the nominated MAOP of the test network. The criteria for pneumatic strength testing are shown in **Table 2** as per *Section 8.4.2.2. of the PEGN Code [APGA, 2019]*.

Exclusion zones are generally not required for leak tests as the network has been proven to have adequate structural integrity and no significant leaks. However, it is recommended that exclusion zones be maintained for above-ground pipe sections and testing equipment – ensuring unauthorised people are excluded from test areas.

Table 2: Pneumatic Leak Test Criteria

Pneumatic Leak Test Method	Acceptance Criteria
<ul style="list-style-type: none"> Allowable Pressure Loss (pneumatic pressure decay test). Details of this test method and calculations are described in CP-8-003 Leak Test Methods and Appendix B1 of the PEGN Code, respectively. 	<ul style="list-style-type: none"> The acceptable volume loss is 1 litre/hr/actual m³ volume of test fluid. NOTE: The word "fluid" in this context means air or another gaseous medium.

Tracer gas will not be used for leak testing of the constructed flowlines.

2.2.8 Pipe Survey, Location, and Marker-Signposting

2.2.8.1 Pipe Survey

A survey will be made to locate the Gathering Network (and all related infrastructure) relative to permanent marks and benchmarks conforming to Mapping Grid of Australia (MGA 94) [ICSM, 2021] or other approved datum.

The survey will develop sufficient information on the constructed Gathering Network to satisfy the materials traceability requirements of the PE.

Specific survey locations that will be captured occur at crossings (such as road, rail, creeks, rivers, third-party infrastructure) at changes of direction, fence lines, and boundaries.

2.2.8.2 Survey Accuracy

The uncertainty of the x-y coordinates shall not exceed 500mm, and the uncertainty of the as-built top of pipe level shall not exceed 50mm.

2.2.8.3 Pipe Location

All buried flowlines will have a detectable tracer wire installed, including bored sections. This detectable tracer wire enables the pipe location to be traced, with a pipe locator, reducing the likelihood of damage during future excavations. Tracer wire will be metallic, electrically insulated and have a minimum diameter of 14 gauge. Tracer wire shall be resistant to corrosion damage by either using coated copper wire or by other means.

2.2.8.4 Marker Signposting

Marker signs will be installed to alert people of the Wastewater Gathering Network's presence and, if they plan to carry out work nearby, of the possible consequences of inflicting unintended damage. Markers also instruct those intending to work near the Gathering Network to contact the nominated network operator and provide relevant contact details. Pipe marker signs shall conform to the requirements for safety signs per AS 1319 '*Safety Signs for the Occupational Environment*' [INDUSTRIAL WARNING SIGNS COMMITTEE SF/5, 1994].

Marker signs shall:

- Indicate the approximate position of the pipe.
- Indicate that excavating near the pipe is hazardous.
- Include a direction to contact the Gathering Network operator before commencing excavation near the network.

Signs shall be placed at the following locations and be inter-visible:

- Both sides of public roads.
- Both sides of railways.
- At each property boundary (and at internal fence lines as appropriate).
- Both sides of creeks and rivers.
- Both sides of vehicle tracks.
- Each change of direction.
- At utility crossings (buried or above ground).
- At all network facilities.

Signs shall also be placed at all other locations where sign-marking (the network location) is considered to contribute to network safety, by properly identifying its location.

2.2.9 **Commissioning**

Commissioning is broadly defined as the range of activities required between mechanical completion of the plant or network, and its handover for operation. It involves introducing process fluids and the functional and performance testing of all related equipment and systems before handover.

Commissioning will always be preceded by acceptance pressure testing of the relevant network section. As this Gathering Network is very simple in design and operation, the commissioning plan will be equally simplistic.

Commissioning will ensure that both the PE pipes and all associated facilities are checked and verified by a competent and qualified inspector, ensuring they are fit for the nominated operating envelopes for all Gathering Networks. Such facilities shall include valves, flanges, protective devices (pressure safety valves), electrical and instrumentation equipment where applicable.

The network shall not be considered ready to commence or recommence operation until, as a minimum, the following checklist has been completed:

1. The network safety management study has been reviewed, and the network determined as ready for operation.
2. The strength and leak test requirements have been achieved and documented.
3. The MAOP has been established.
4. All tie-in welds to existing facilities that have not been subjected to item (2.) above, have been subjected to the requirements of *Section 7.5.1, 7.7.1, 7.8 and 7.9 of the PEGN Code*.
5. All components have been tested for satisfactory operation.

Sufficient operating, maintenance and emergency personnel have been trained and qualified as competent.

2.2.10 ROW Reinstatement

After backfilling has been completed, construction tools, equipment, and debris will be removed. Areas disturbed by the installation will be reinstated as soon as practicable, including pulling stockpiled timber back over the ROW. Where pipelines are not co-located with new or existing access tracks, or previously cleared areas stockpiled timber will not be pulled back over the flowline ROW so that light vehicles can traverse the alignment for inspections and maintenance.

Due to the irregular use by only light vehicles, revegetation will occur, and management of regrowth of trees that will impede access will be carried out on an as needs basis.

Appropriate measures shall be taken to prevent erosion and minimise long-term degradation of the environment (e.g., the construction of contour banks or diversion banks).

Fences that have been removed to provide temporary access to the route will be re-erected.

2.2.11 ROW Inspection Maintenance and Monitoring

ROWs will be inspected before, and after, the wet season for evidence of subsidence and/or surface and tunnel erosion. Where identified subsidence, surface and tunnel erosion will be rectified before the onset of the wet season.

2.2.12 Materials Selection

Polyethylene is a thermoplastic and behaves differently from metals.; however, these properties are well-known and are embraced in Australian and other international standards.

PE100 resins used in today's pipes have high toughness, excellent resistance to slow crack growth and rapid crack propagation. They also have an inherent resistance to water and many chemicals. Polyethylene is now the material of choice for many water, wastewater, gas, and other applications.

Materials used for the construction of the Gathering Network will comply with *Section 3 of the PEGN Code* [APGA, 2019].

2.2.13 Watercourse Crossing

Directional drilling is the default methodology for crossing a waterway with defined banks or a defined drainage channel with a buried service. A waterway crossing study will be carried out where a buried service alignment crosses a waterway with defined banks or a defined drainage channel before construction is carried out. If this study indicate that an open trench method of crossing can be constructed without adversely impacting water flow patterns or waterhole water retention timings, open trench methods will be used; if not, directional drilling will be used. Before any flowline construction work is carried out in watercourses, Imperial A will check the 7-day forecast to ensure an adequate window for the trenching, installation, backfill, and stabilisation works to be carried out. A decision tree for the Flowline waterway crossing methodology is presented in Figure 7 Imperial A considers that when applying the above methodology, that the residual risk is ALARP and acceptable when crossing a watercourse.

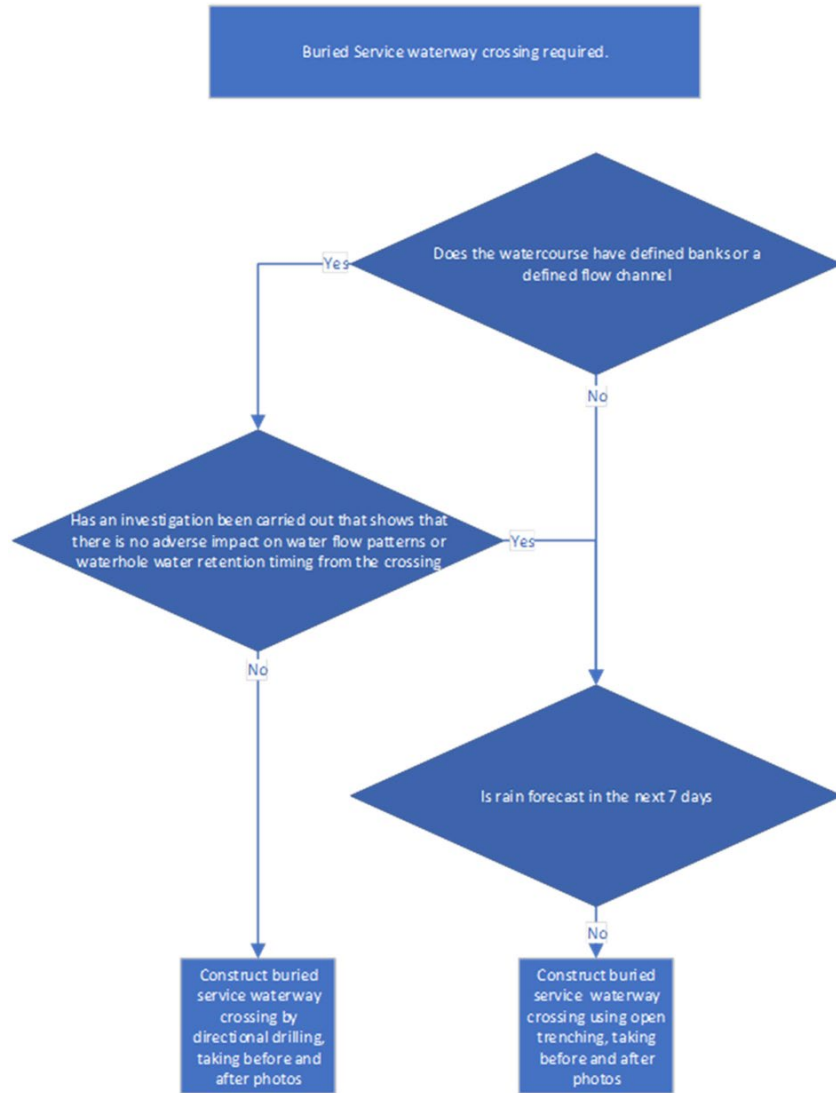


Figure 7: Buried Service Waterway Crossing Methodology Decision Tree

2.2.14 High Point Vents, Low Point Drains and in Field Valves

Water/wastewater flowlines in undulating areas are prone to air locking; as a preventative method, High Point Vents (HPVs) will be installed in these areas to release gas build up from the flowlines. HPVs will be visually checked weekly when flowlines are in use, i.e., whenever flowlines contain wastewater.

Gas flowlines in undulating areas are prone to water locking; as a preventative method, Low Point Drains (LPDs) will be installed in these areas to release water from the gas flowline. LPDs will be visually checked weekly when flowlines are in use, i.e., whenever flowlines contain wastewater.

Infield valves will be installed as required to allow efficient use of the network.

Any above-ground infrastructure outside of well pad fence lines will be barricaded to prevent livestock access. Erosion and sediment controls will be constructed.

2.2.14.1 Abandonment

When a network is abandoned, it shall be disconnected from all fluid sources and flushed clear of fluids. Disposal of any fluids shall meet all relevant environmental and safety requirements. As the Gathering Network will be constructed from PE, the risk of subsidence caused by flowline collapse is minimal.

When a network is abandoned, the following additional requirements shall be completed:

- The cutting and removal of all sections of buried pipes that come to the surface.
 - At a minimum of 750 mm below the natural surface, or
 - At the pipe depth, whichever is the lesser.
- The removal of all surface equipment.
- The removal of all signage associated with the network on completion of the post abandonment maintenance period.

Obtaining landowner releases for the completed abandonment.

Upon completing the network section's abandonment in place, the records identifying and locating sections of the abandoned network shall be prepared as part of the relinquishment procedure.

These records shall be publicly available to prevent possible mistakes in identifying an abandoned network as an operational network.

3 Well Pad Construction

3.1 Overview

Well pads will be constructed as required to provide a safe and efficient workplace for drilling and other well pad regulated activities.

The construction of well pads will include:

- Clearing and levelling the well pad work area.
 - Constructing lined pits for the storage of freshwater, drilling fluids, and drilling cuttings.
 - Constructing water production and groundwater monitoring bores.
 - Constructing tank pads for the placement of above ground enclosed or open topped treatment tanks.
 - Installing a drilling cellar and conductor.
 - Installing above ground tanks for storing and disposing of frac flowback fluid and produced water.
 - Fencing well pads to prevent livestock and personnel entry.
 - Clearing firebreaks.
 - Installing erosion and sediment control devices.
-

3.2 Methodology

Timber and vegetation will be cleared from the site and stockpiled for future rehabilitation activities.

The site will be levelled and compacted using on-site materials as far as practicable.

Pits will be constructed using bulldozers and excavators, with berms consolidated with watering and compaction.

The footprint for any above-ground tanks will be consolidated and tested to the tank supplier's requirements.

Water monitoring production and monitoring bores will be drilled by licensed drillers, in line with permit conditions.

Fire breaks will be constructed and maintained at wellpads.

Erosion and sediment controls will be constructed at wellpads.

Wellpads will be fenced to exclude livestock, barbed wire will be used in line with local pastoral practices. An indicative wellpad layout is attached in Figure 9.

3.3 Cut and Fill Well Pad Methodology

Where a natural slope is too great for a drilling rig to operate safely, the well pad will be cut and filled to flat, using the following methodology.

3.3.1 Vegetation Stockpiling and Dirty Water Filtration

Vegetation will be stripped from the site and windrowed along the downslope section of the well pad and fire access track. This has the benefit of filtering any runoff from the work site during construction, and from the well pad fill batters post-construction, as shown in **Figure 19**.

3.3.2 Topsoil and Clean Water Diversion

Topsoil from the site shall be stripped and windrowed above the cut batter and fire access track, on the upslope extent of the site as shown in **Figure 8** and **Figure 19**. Care should be taken to ensure that water intercepted by the topsoil bund does not drain back onto the pad or to dirty water catch drains.



Figure 8: Topsoil Windrow Above the Cut Batter used to Divert Clean Water away from the Well Pad

3.3.3 Levelling the Well Pad

The well pad will be cut and filled to flat, balancing the on-site material volumes to avoid the need to bring material onto the site or remove material from the site. The well pad will be compacted to provide a good working surface and crowned along the Plant North/South Centreline to achieve a 1% fall back to the well pad edge draining to the plant East and West batters. Both cut and fill batters will be at a 1:1 slope.

The cut batters will be protected from erosion by the topsoil stockpile/clean water diversion bund preventing significant water volumes from washing over them, as shown in **Figure 10**.

The fill batters will be protected by constructing a bund at the top to prevent water from the well pad from running down the batter face, as shown in **Figure 10**.

3.3.4 Well Pad Drainage

Significant volumes of water are expected to runoff from the compacted pad. This water will drain plant East and West on the well pad to shallow spoon drains constructed inside the bunds at the top of the fill batters and the toes of the cut batters. These drains will be contoured to take the runoff to the cut/fill point of the well pad, as shown in **Figure 10**.

3.3.5 Sediment Control

Drains shall be installed from the cut/fill point on the pad to type 2 sediment controls, as shown in **Figure 10**.

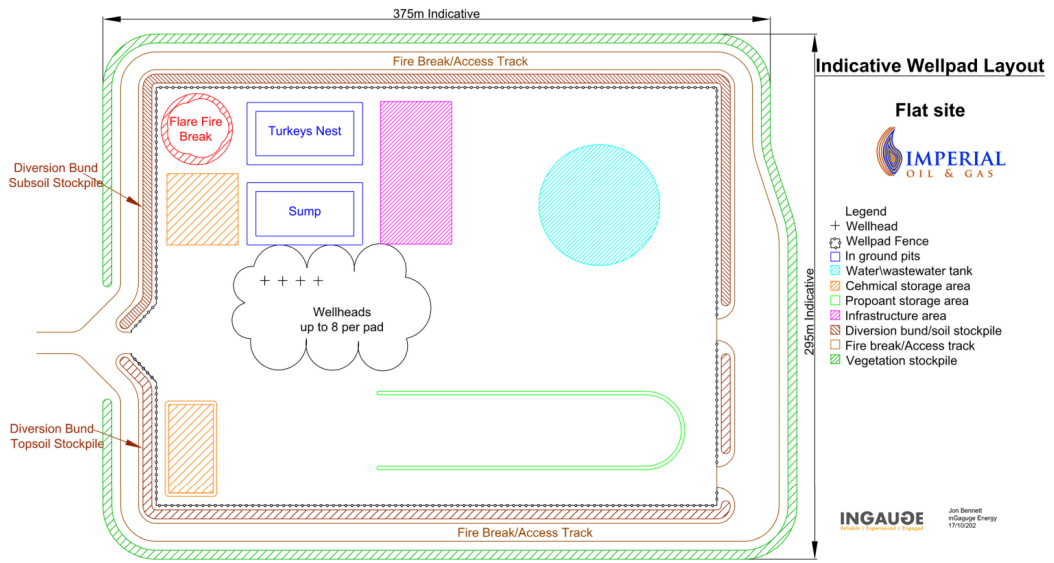


Figure 9: Indicative wellpad layout

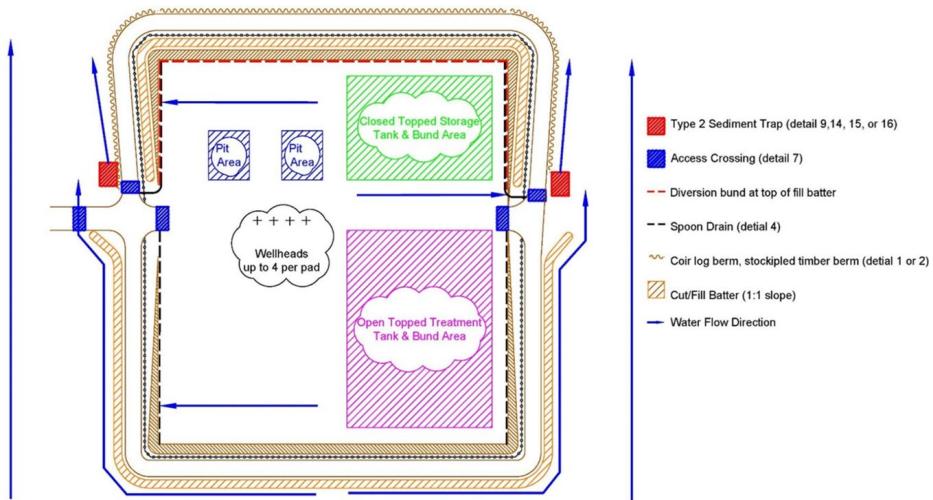


Figure 10: Indicative erosion and sediment control devices for wellpads

4 Water Bores

4.1 Overview

Water bores are required for:

- Provide access to aquifers that could be impacted by regulated activities to establish baseline water qualities.
- Provide access to aquifers that could be impacted by regulated activities to measure any impacts.
- The production of water required to carry out regulated activities.

Where water bores are to be drilled for the above purposes:

- A Bore Work Permit will be sought and issued by Water Resources for all water bores drilled.
- All bores will be drilled, commissioned, and tested according to the issued Bore Work Permit conditions by appropriately licensed drillers.
- Where a water bore is co-located with a well pad, no additional clearing will be done beyond the extent required for the well pad, including fire access trails and breaks.
- Where a water bore is not co-located with a well pad, water bores will be placed in previously cleared or naturally cleared areas as a priority where practicable.

4.2 Camps and Campsites

A camp will be constructed and operated as part of the Carpentaria Pilot Project for the longer-term appraisal activities. Temporary camps will be utilised for the shorter duration construction, drilling and hydraulic fracturing activities. Existing disturbances or wellpads constructed under this work program will be used for these temporary camps.

5 Gravel Pits

5.1 Overview

On-site material will be used for the majority of civil construction works. Gravel will be required to give a better running surface on some road sections and may be required to cap some well pads, depending on the on-site material.

Where gravel is required, local gravel pits will be established; the establishment of these pits will include the following:

- Gravel pits will use the same site selection criteria as well pads.
- Clearing of vegetation, to be stockpiled around the perimeter of the cleared area for rehabilitation.
- Stripping of topsoil (if required):
 - Topsoil will be stockpiled around the upslope side of the gravel pit to divert overland flow from entering the gravel pit.
 - If there is no topsoil on-site (e.g., Pea Gravel site), a diversion bund will be constructed upslope to divert any overland flow.
- A whoa boy will be constructed on the access track so that water does not flow down the access track into the gravel pit.
- Batters will not be steeper than 1:1, to allow safe passage for animals, and people.
- Gravel pits will not be fenced.
- Gravel pits will intentionally be kept wide and shallow to facilitate rehabilitation.

An indicative layout for a gravel pit is shown in Figure 11.

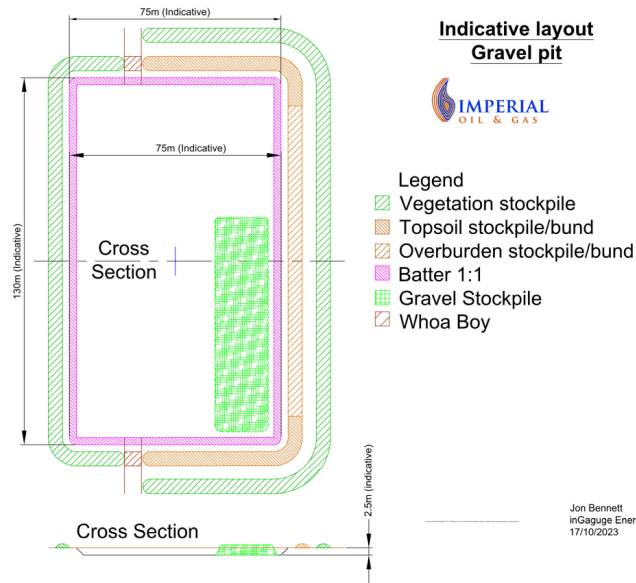


Figure 11: Indicate Gravel Pit Layout

6 Drilling

6.1 Overview

There are three potential well designs to be carried out under this Work Program:

1. A cased horizontal production well with a plugged back open hole vertical pilot.
 - o The open hole vertical pilot in this design is drilled and logged to confirm the prognosed formations depths before being plugged back to the horizontal kick-off point and horizontal section drilled and cased.
2. A cased horizontal production well from a plugged back cased hole vertical well.
 - o The bottom section of the vertical cased hole in this design is plugged back to the horizontal kick-off point, a whipstock is set, and an exit is milled into the casing to allow a horizontal section to be drilled and cased.
3. A cased horizontal production well without a vertical pilot.

The surface and intermediate hole sections are the same under all three well designs so that they will be covered once; the production section for each design will be covered in dedicated sections below.

This Work Program also includes multi-well pads, where more than one wellbore is drilled from a well pad; the details of the extra complexity of collision avoidance for multi-well pads are covered in **Section 6.5**.

6.2 Surface Hole Section

The surface hole section will be drilled from the pre-installed cellar and conductor to a depth that isolates any shallow aquifer/s.

During drilling of in the Beetaloo Sub Basin, total drilling fluid losses are generally observed in the shallow aquifers. This scenario is anticipated in current well designs, with high permeability conduits, fractures and cavernous zones expected in karstic formations. Loss of circulation material (LCM) is generally not successful for responding to fluid losses in these formations. When total losses occur, the drilling fluid systems are reduced back to water to maintain dynamic well control while minimising drilling additive losses to the formation.

The 'surface casing' will be installed into the surface hole and cemented (specifically engineered cement) to seal the aquifer off from the rest of the wellbore to prevent fluid crossflow between formations. During cement operations, cement may also be lost to the formation resulting in cement slumping or "patchy" cement sections. If cementing of the surface casing for a well is unsuccessful (i.e., the cement does not return to the surface or slumping is observed), top-up cement job/s will be undertaken. This process involves spotting cement from the surface in the annulus of the surface casing and formation.

6.3 Intermediate Hole Section

The surface casing shoe will be drilled out; drilling will then progress down to the target intermediate hole depth for a vertical well, or the 'kick off' point for a horizontal well. When the intermediate hole section reaches its target depth, the intermediate casing is installed and cemented to isolate potential hydrocarbon-bearing zones and the surface.

A Formation Integrity Test (FIT) or Leak-off Test (LOT) will be carried out at the intermediate casing shoe to prove integrity before drilling ahead.

6.4 Horizontal Production Hole Sections

A horizontal wellbore can be drilled from a dedicated intermediate section or plugged back from a vertical wellbore.

Where a horizontal wellbore is being drilled from a dedicated intermediate section, the following will apply. The intermediate casing shoe will be drilled out, and a short section of the production hole will be drilled. A FIT or LOT will be carried out at the intermediate casing shoe to prove integrity before directionally drilling ahead.

Where a horizontal wellbore is being drilled from the intermediate section of a vertical open hole pilot, the following will apply. The vertical open-hole section will be abandoned and plugged back to above the kick-off point before directionally drilling ahead.

Where a horizontal wellbore is being drilled from the intermediate section of a vertical cased hole pilot, the following will apply:

- The vertical cased-hole section will be abandoned back to the kick-off point, a whipstock set into the intermediate casing, and an exit point milled into the intermediate casing.
- Once the kick-off operation has occurred, the production section will be directionally drilled horizontally within the selected shale target/s, the horizontal section length within the selected shale target will be up to 3,500m.

When drilling horizontal wellbores or, for that matter, any directional well, standard directional drilling techniques and equipment are employed to enable accurate wellbore direction to be recorded and maintained.

6.5 Collision Avoidance on Multi-Well Pads

An added complexity of multi-well pads is collision avoidance of wellbores; unplanned wellbore collisions can have serious safety and environmental consequences. To minimise the risk of wellbore collision, the position of any existing wellbores and the well being drilled need to be clearly understood and a Separation Factor maintained.

While directionally drilling, standard directional drilling techniques and equipment are employed to enable accurate wellbore direction to be recorded and maintained. A "Separation Factor" for the well is also continually calculated and monitored. The use of separation factors is a standard industry control that has been effectively used for multi-well pad drilling within Australia and internationally.

Industry practice generally maintains a Separation Factor greater than two between well paths unless an internal risk assessment is carried out to avoid wellbore collision. Separation factors are covered in more detail in **Section 6.5.1.1**.

Imperial A will follow this industry practice whilst drilling multiple wells on a pad under this Work Program.

6.5.1.1 Separation Factors

A visual representation of separation factors is provided in Figure 13 and Figure 14. The level of uncertainty of a wellbore's position increases along its path, as shown in Figure 12, due to several factors:

- Relative Depth Error.
 - Error in measuring along the hole depth, e.g., stretch in a wireline.
- Misalignment Error.
 - Error due to instrument misalignment in the wellbore.
- True Inclination Error.
 - Error in inclination reading.
- Compass reference error.
 - A constant error in direction due to misalignment, e.g., gyro error or error in magnetic declination.
- Drill string Magnetisation.
 - Magnetic interference caused by "hot spots."
- Gyrocompass.
 - Error due to gyron Gimbal drift.

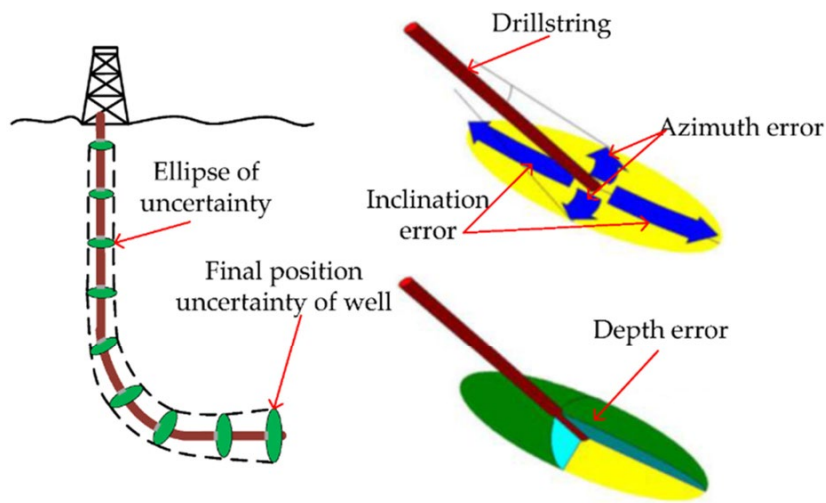


Figure 12: Wellbore Uncertainty [C. P. GOONERATNE et al., 2017; ANGUS JAMIESON, 2012]

Because of this increase in uncertainty along the well path, a Separation Factor is used, rather than standard separation distance. The separation factor is a ratio of the centre-to-centre distance of the wellbores over the sum of the uncertainty of both wellbores, as shown in Figure 13.

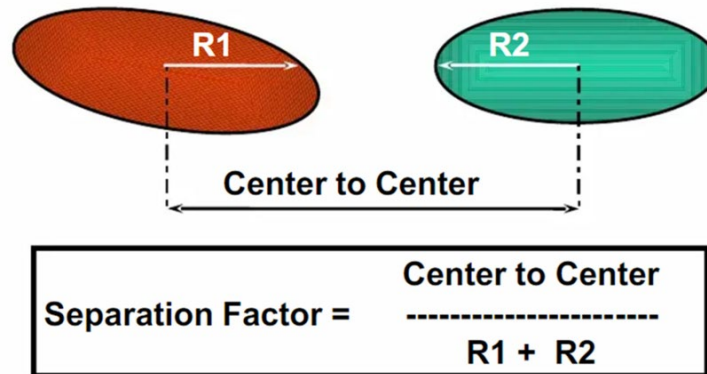


Figure 13: Separation Factor Equation

As shown in Figure 14 separation factor of:

- Greater than 1, the two ellipses of uncertainty do not overlap.
- 1, the two ellipses of uncertainty just touch.
- Less than 1, the two ellipses of uncertainty overlap.

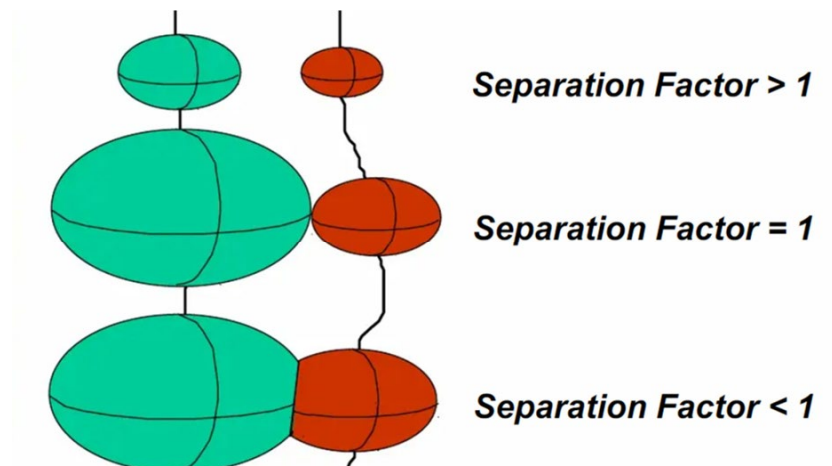


Figure 14: Separation Factor Comparison

7 Diagnostic Fracture Injection Test (DFIT)

7.1 Overview

During a Diagnostic Fracture Injection Test (DFIT), a relatively small volume of freshwater (without proppant) is injected into the target formation, creating a hydraulic fracture. After the injection, the wellbore pressure is monitored for a short period (up to an hour). The pressure measurements are used to infer properties of the formation, including the leak-off coefficient, permeability, fracture closure pressure (related to the magnitude of the minimum principal stress and the net pressure), and formation pressure. These are key parameters for hydraulic fracture design and reservoir engineering in shale.

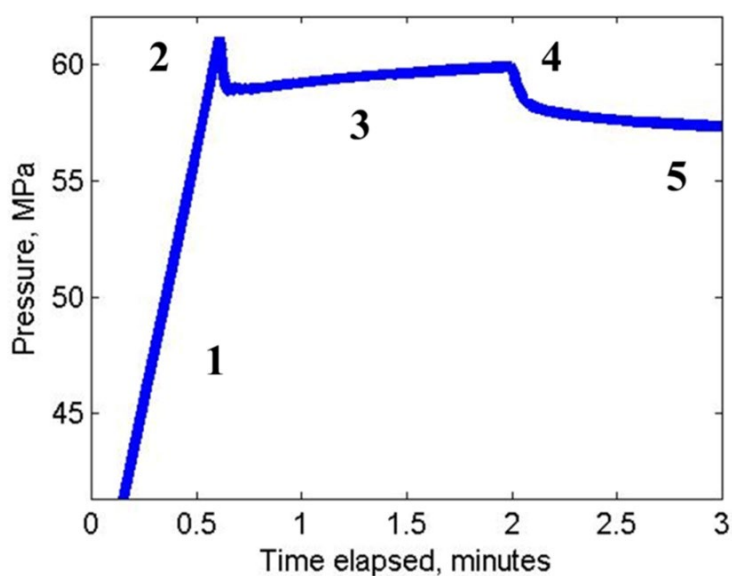


Figure 15: A Typical Pressure Response During Injection in a DFIT [MARK MCCLURE, 2017]

During period #1, a fracture has not formed, and wellbore storage controls the pressure behaviour. The leak-off point occurs at #2, the fracture propagation pressure is reached at #3, and the ISIP (initial shut-in pressure) is reached at #4. DFIT analysis is primarily interested in analysing the trends in pressure in the hours and days after shut-in.

8 Perforation

8.1 Overview

The casing at the identified formation is perforated to provide communication between the wellbore and the formation target zones. The perforation selection method will depend on the size, penetration depth, and hole type required to allow recoverable flow.

There are three primary methods of perforation that can be used as described below:

- **Hydro-jetting** – uses sand and water jetted through small holes in the bottom hole assembly to create holes in the casing across the target formation – there is no perforating charge. Hydro-jetting allows for targeted or pinpoint perforating, making between 3 and 4 holes per event.
- **Wireline Conveyed Perforating (WCP)** – the most widely used perforating technique in the Cooper Basin. As the name suggests, WCP uses a wireline to deploy the perforating charge.
- **Tubing Conveyed Perforating (TCP)** – uses the same technology as conventional wireline perforating but is run using a coiled tubing unit or jointed tubing (not wireline). TCP is the preferred perforating method when operating in underbalanced or overbalanced conditions.

9 Hydraulic Fracturing

9.1 Overview

Hydraulic Fracturing (HF) is a commonly used oil and gas well completion process. It typically involves injecting a slurry of water, sand, and a small amount of chemicals under high pressure into a bedrock formation via the well. This process is intended to create new fractures in the rock and increase the size, extent, and connectivity of existing natural fractures. HF is a well-stimulation technique used commonly in low-permeability rocks like tight sandstone, shale, and some coal beds to increase oil and/or gas flow to a well from petroleum-bearing rock formations.

During HF activities, HF fluid is pressurised by high-pressure pumping units and directed downhole via a manifold to discrete target intervals along the vertical or horizontal wellbore (referred to as "stages"). Each stage is isolated and perforated using a plug and perforation gun assembly deployed via wireline. The fractures propagate radially from the well through the target formation as the pressure is sustained. Once optimal fracture propagation has been initiated, the proppant (sand) is pumped down the well and into the open fractures to prevent them from closing. This process is repeated for each stage. The final number of stages pumped is dependent on the useable length of the wellbore, the design fluid rates, the number of perforations per stage and in-situ geological conditions. Once all stages are complete, the well is suspended, awaiting completion and well-testing activities.

During each HF, wellbore pressures are monitored to ensure operations have not compromised the production casing or the cement barriers' integrity.

HF fluid primarily consists of water and sand (proppant), plus chemicals commonly found in food and other domestic household products.

All fluid additives (water and chemicals) and sand are mixed on the surface immediately before being pumped through HF equipment. The mixture and pumping schedules (rates, volumes, and proppant) are based on an HF model, determining the desired fracture attributes. The HF model will be completed before the commencement of HF activities and underpinned by a Mechanical Earth Model (MEM). The MEM will be generated from data collected during drilling, wireline logging, core analysis and DFIT tests. The HF fluid mixture and pumping schedule are continuously updated during and after each stage to ensure optimal outcomes. An example of the process and a modelled side view fracture is illustrated in Figure 16 and Figure 17.

All HF activities will be undertaken as per *the Code* and relevant NT, and Federal Government, legislations, and regulations.

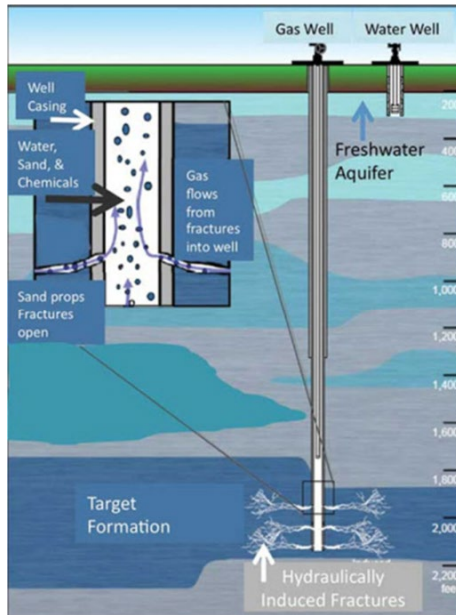


Figure 16: Indicative Hydraulic Fracture Schematic [EPA (US), 2011]

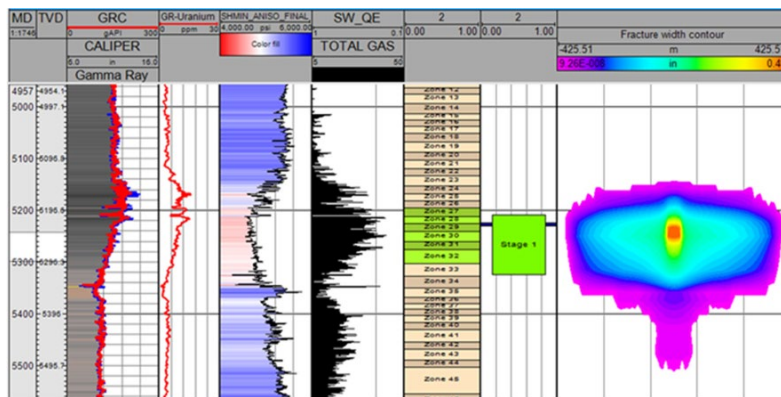


Figure 17: Example HF Model

9.2 Hydraulic Fracture Stages

The hydraulic fracture in a horizontal well can be placed several ways, but the most common way is to use a plug and perforate method in multiple stages. This method involves using perforating tools to place perforations, or holes, in the steel casing and cement around the wellbore. The perforations are placed in sections along the wellbore length within the target shale.

The fracture stimulation is then pumped, and the fracture is placed through these perforations. The wellbore is broken into sections called "Stages" to control the HF operation and allow each stage to be successfully placed.

The following images demonstrate the process followed. The first stage of the wellbore is perforated, as shown in Figure 18.

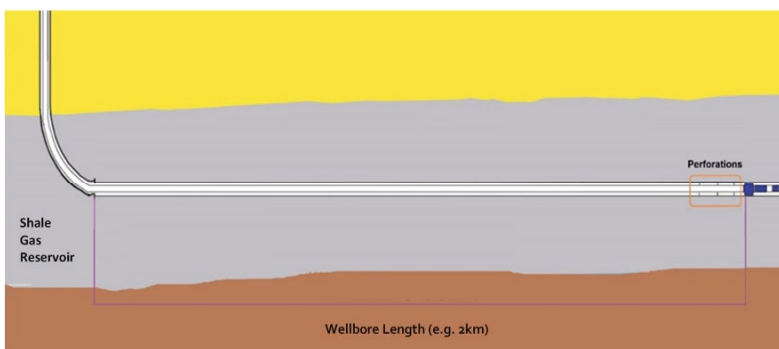


Figure 18: Perforation of 1st Stage

The first stage of hydraulic fracture is then pumped, as shown in Figure 19.



Figure 19: 1st Stage Hydraulic Fracture

After the first stage of hydraulic fracture is pumped, a plug is set to isolate that stage from the balance of the wellbore; the second stage is then perforated, as shown in Figure 20.

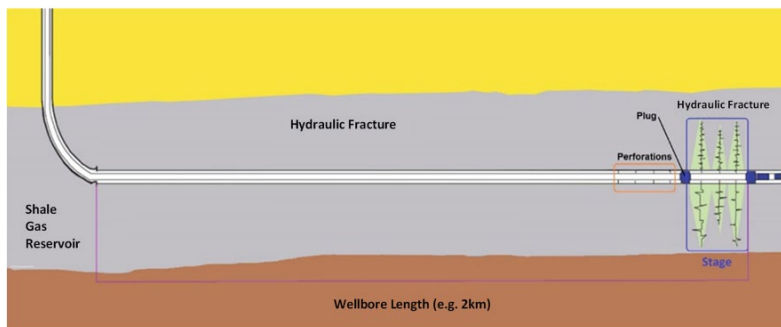


Figure 20: 1st Stage Plug, 2nd Stage Perforation

This process is repeated along the wellbore until the entire length of the target zone of the wellbore is hydraulically fractured. Each of the stages of the wellbore is separately treated with a hydraulic fracture job. There will be several smaller fractures within each stage that each come from the various perforations put in the casing.

Each stage is designed to optimise the available fluid and the pumping capacity of equipment on-site, balancing the trade-off between the size of a stage for efficiency and placement control. If more stages are placed in a certain length, the size of each stage will reduce.

In addition, as the well gets longer and more perforations and more fracture stages are added, the additional length the fluid travels adds friction pressure such that the volume pumped per stage has to be reduced; therefore, the stages tend to get smaller as the well gets longer and the number of stages increases. As a result, the volume pumped per fracture stimulation stage is not standard and is not a fixed volume, and the length of a stage is not a fixed length. The volume of fluid pumped is therefore not proportional to the number of stages placed.

The number of stages hydraulically fractured in a length of the wellbore can be varied to optimise this control; Figure 21 and Figure 22 show the same length wellbore, with the same amount of hydraulically fractured length and the same total fluid volume broken into five and ten stages, respectively.

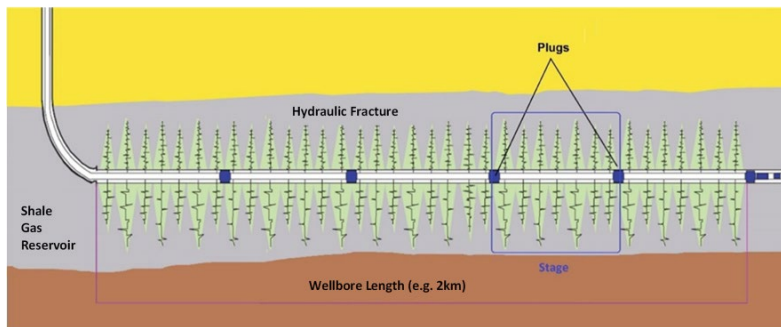


Figure 21: Wellbore Split into 5 HF Stages

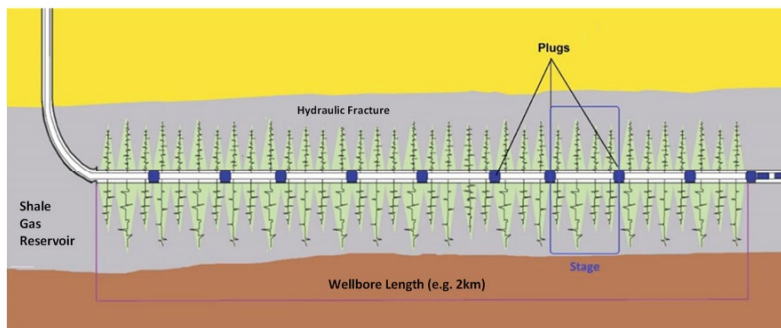


Figure 22: Wellbore Split into 10 HF Stage

As each stage has an incremental cost, a wellbore that is hydraulically fractured with a higher number of smaller stages will have a higher cost than the same wellbore fractured with fewer larger stages, even though a similar amount of fluid and proppant is pumped; however, the resultant design flow control may justify this cost.

The amount of hydraulic fracture fluid chemical and proppant use is primarily based on the type of fluid used in the design, the wellbore length, the perforation spacing and the design volume of each fracture node, not the number of stages.

Once all the stages are complete, and regardless of the number of stages, the isolation plugs are removed, and access to the full length of the wellbore is regained as part of the cleanout hydraulic fracture operations, as shown in Figure 23.

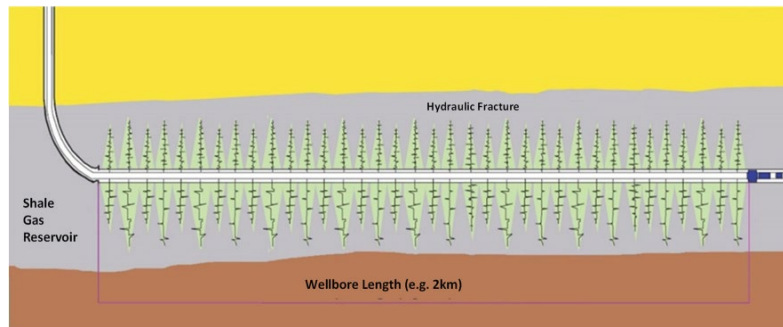


Figure 23: Wellbore with Plugs Removed

The design for the exploration wells under this EMP calls for up to 50 stages; however, these stages will be smaller and more closely spaced than if fewer stages were to be pumped in the same well. The total volume of fluid pumped is based on a range of design inputs and will not necessarily increase simply because of the number of stages.

9.3 Proppant and Chemical Additives

The chemicals used for hydraulic fracture HF account for less than 1% of the mixture to assist in carrying and dispersing the sand in the low permeability rock; the balance is freshwater and sand. These chemicals are also commonly used in household products, including food additives, soap, cosmetics, and toothpaste.

All chemicals added to HF fluid perform a specific purpose, including:

- **Acids and bases:** controls pH and clear the perforations before HF.
- **Chemical inhibitors:** such as scale prevention.
- **Biocides:** controls or eliminates bacteria in the fluid to ensure that it isn't introduced to the target formation.
- **Clay control:** prevents clays from swelling.
- **Corrosion inhibitors:** prevents equipment from rusting.
- **Friction reducers:** reduces friction between the HF fluid and piping, allowing the fluid to be injected further without pressure drop.
- **Surfactants:** reduces the surface tension of the hydraulic fracturing fluid; this allows the HF fluid to be injected further without pressure drop.
- **Viscosity regulators:** increases or decreases the thickness of a fluid.

All transportation, handling, storage, and disposal of chemicals will comply with the required *NT regulations*, this includes:

- **Transportation:** from the supplier warehouse to the well pad and between well pads (*Transport of Dangerous Goods by Road and Rail (National Uniform Legislation)* [DEPARTMENT OF THE ATTORNEY-GENERAL AND JUSTICE, 2010]).
- **Use:** handling, blending, injecting etc. (*NT Dangerous Goods Act, Work Health and Safety Act, and the Code* [NORTHERN TERRITORY OF AUSTRALIA, 1998A, 2011; DENR et al., 2019]).
- **Storage:** storage of chemicals and recovery of fluids (including storage in produced water and flowback fluid treatment tanks) at the well pad and associated vendor chemicals (*NT Dangerous Goods Act, Work Health and Safety Act and the Code* [NORTHERN TERRITORY OF AUSTRALIA, 2011; DENR et al., 2019; DEPARTMENT OF THE ATTORNEY-GENERAL AND JUSTICE, 1998]).
- **Disposal:** recovered vendor chemical additives in wastes and hydraulic fracturing flowback (*NT Waste Management and Pollution Control Act 1998* [NORTHERN TERRITORY OF AUSTRALIA, 1998B]).

For further information, see **Appendix 06** (Wastewater Management Plan) and **Appendix 07** (Spill Management Plan).

9.3.1 Tracers

Unique ID tracers can be detected at extremely low concentrations (ppb) and are used to determine each fracture Stage's performance. In doing this, the knowledge learnt allows for optimising resource extraction in future campaigns. The presence and concentration of chemical tracers detected during flowback can be measured to determine each stage's fluid recovery relative contribution.

Tracers are harmless chemicals designed to be unique in composition every well. They can be absorbed into both the water or gas phases, allowing them to be delineated from source due to each stages unique tracer.

9.4 HF Equipment

Fracturing equipment is operated across different pressures and injection rates specific to the well. The equipment is highly mobile, designed to comply with state, territory and federal regulation and fitted with safeguards to ensure compliance and safety systems.

9.4.1 Wellhead

The wellhead is the portion of the well's anatomy that shows above ground. It comprises housings and valves that cap the wellbore and serve as a point used to inject into and control the well. The wellhead provides the primary surface barriers for well control; an example is shown in Figure 24.

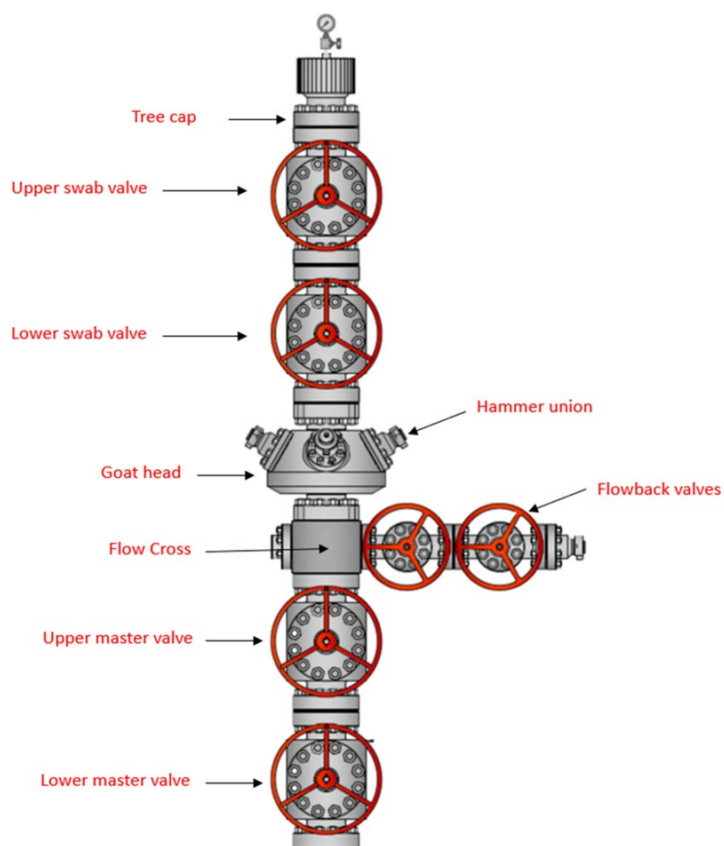


Figure 24: Typical HF Wellhead

The wellhead integrity will be regularly verified during the fracturing operations by testing conductivity pressure against the main wellhead valves. Additionally, pressure will be recorded of the secondary seals and the seals between the tubing head and spool.

Once the fracturing operations are completed, the upper valves (above the production flow-cross) can be removed as they are not required for flowback or appraisal (production) test operations.

9.4.2 Sand Trailer Units

Sand trailers are ample storage, and delivery trailer units are used to hold the proppant (sand or ceramic material) needed for the HF operations.

9.4.3 Blender Units

Blender units are used to mix the proppant and fluid additives before their injection into the well. The blended HF fluid, without proppant, is referred to as the "clean fluid". The blended HF fluid, with proppant added, is referred to as "slurry". Chemical additives are precisely measured, controlled, and recorded by the blender units throughout the HF treatment process.

9.4.4 High-Pressure Pumps

High-pressure pumps are required to inject the hydraulic fracturing fluid mixtures from the Blender Unit down the well via the surface lines and wellhead or coiled tubing unit. The pumps contain programmable pressure triggers (kick-outs) to prevent pressure from exceeding the wellbore design limits. High pressure treating iron (pipes, manifolds, connectors, etc.) connecting the HF pumps and the wellhead also contains pressure safety valves (PSVs) set to open at a pre-set pressure to ensure the well components are protected.

9.4.5 Control and Data Acquisition Unit

An on-site mobile office is connected to all units during HF treatment to monitor, record and plot all data received throughout the treatment. Supervisors will continually monitor and control the treatment to ensure the process goes according to the design.

10 Completion

10.1 Overview

A completion is a generic term used to describe the events and equipment necessary to leave a wellbore ready for production once drilling operations have been concluded, including but not limited to the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well.

A completion will be run into the well for well testing after cased hole fracture stimulation if the initial flowback rates cannot sustain free flow up the casing. The completion will be run using a workover rig; this will involve the following activities:

- Ensure the well is dead using appropriately weighted fluid.
- Cleanout the wellbore by running tubing into the well and circulating out any debris from the wellbore, including proppant and plugs.
- Run tubing into the well.
- Land the tubing in a hanger in the wellhead.
- Set a packer to isolate the tubing annulus.
- Install surface master valves and pressure test wellhead seals.
- Install Flowback and EPT surface equipment for well testing.

11 Flow-back and Extended Production Testing, and Appraisal Activities

11.1 Overview

Flowback and Extended Production Testing (EPT), and appraisal activities are carried out to remove the HF fluid from the formation and validate the well production rates over an extended period of time to determine whether the shale gas resource identified is commercially exploitable. A three-phase separator is connected to the wellhead's outlet; the separator splits the well flowback fluids into gas, oil, and water by gravity level controllers.

Depending on the composition, the gas is directed to flare, condensate to storage tanks or flare, and water to flowback tanks, directly to storage or treatment tanks, or to the water/wastewater flowline network. All gas, water and condensate flow volumes are measured and recorded. A generic layout of a flowback and EPT package is shown in Figure 25 below.

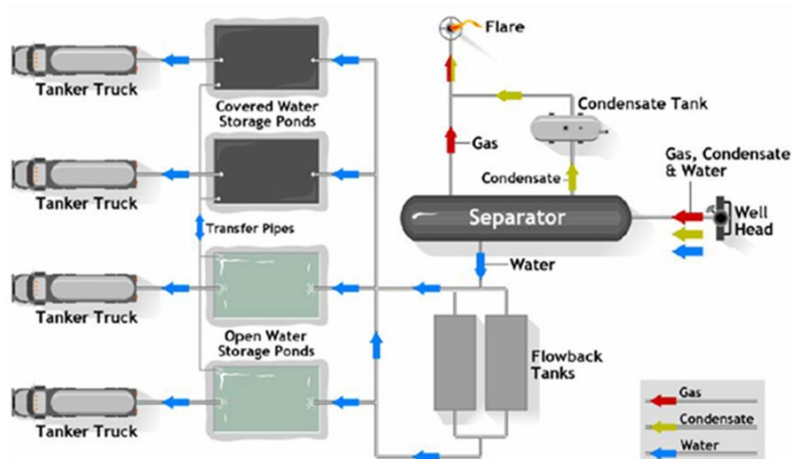


Figure 25: Example of Well Test Equipment Schematic [ORIGIN, 2021]

11.2 Flowback and EPT Equipment

11.2.1 Separator

The separator package splits the comingled flow from the wellbore into gas, water, and condensate. All gas, water and condensate flow volumes are measured and recorded.

11.2.2 Above Ground Storage Tanks

Temporary water storage and treatment tanks will be utilised on-site during the hydraulic flowback and EPT process.

11.2.3 Flare

Produced gas, and pending results, potentially condensate, during EPT will be sent to a flare system to allow a controlled release and gas burning. It is equipped with an autoignition system that provides electrical impulses to generate a spark every 1.3 seconds to ensure that the flare is always operational. Any flares used will have a tip efficiency of greater than 96%.

11.3 Sale of appraisal gas

Extended well testing is required to determine whether the shale gas resource identified is commercially exploitable, which would require a material amount of gas to be flared or vented to the environment. Given this, in order to reduce the environmental impacts of the flaring or venting, not to waste the gas resource unnecessarily, provide economic benefits to traditional owners, and to provide some revenue to Imperial to offset the costs involve in the extended production testing; Imperial proposes to seek the agreement of traditional owners, the NLC and the NT Minister responsible for the Petroleum Act to the use of the gas that would otherwise be flared or vented as appraisal gas which can be sold with revenues to Imperial and royalties to traditional owners and the Territory For the readability of this document, Imperial has called the agreement to be sought for the use of the gas that would otherwise be flared or vented as appraisal gas a Beneficial Use Agreement (BUA).

If a Beneficial Use Agreement can be established, gas will go to the gas gathering network rather than to flare after the initial well clean-up. The gas gathering network will transport the gas to the compressor station for compression and subsequent sale.

12 Gas compressor station

A gas compressor station will be installed and operated as part of the Carpentaria Gas Project. The Carpentaria Gas Project compressor station takes gas from the low-pressure gathering network, conditions it and increases the pressure of the gas for discharge into the high-pressure sales gas pipeline, then into the Daly Waters to McArthur River Gas Pipeline. The Carpentaria Gas Project compressor station will run 24 hours per day, seven days per week. **Figure 26** shows an indicative compressor station layout.

The following subsections provide an overview of the process flow through a compressor station.

A high-level process flow of the Carpentaria Gas Project compressor station, the major process stages include:

1. Water removal upstream of compression
2. Gas compression
3. Water removal & gas dehydration downstream of compression
4. Metering and composition analysis of sales gas
5. Water treatment
6. Fuel gas and flare systems

Figure 27 shows a schematic of the above process flow relative to the Carpentaria Gas Project

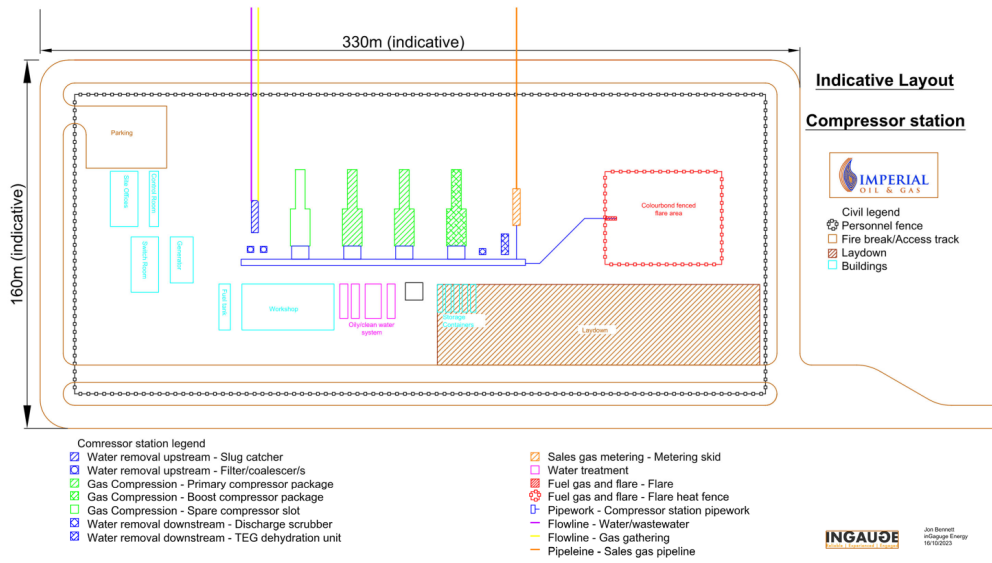


Figure 26: Indicative compressor station layout

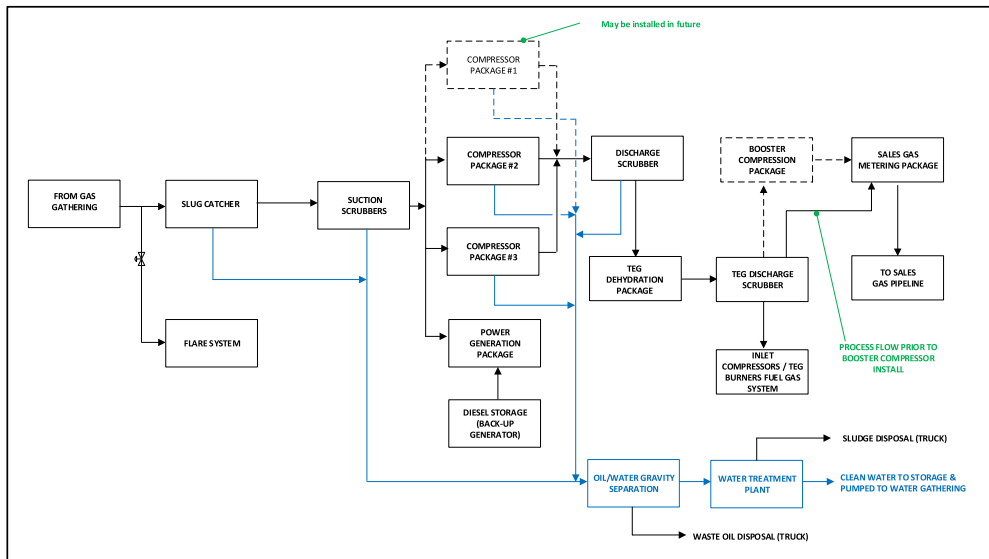


Figure 27: Indicative Compressor station process flow

12.1 Water Removal Upstream of Compression

Gas from the field gathering network will first enter a slug catcher, a slug catcher is a horizontal two-phase separator vessel that is design to capture any potential slugs of free water that may enter the compression facility from the gas gathering network. Any water collected in the vessel is automatically drained to the wastewater system. **Figure 28** shows an indicative slug catcher.



Figure 28: Indicative Slug Catcher

Downstream of the slug catcher, filter/coalescer vessel/s are installed to further remove water from the gas stream. **Figure 29** shows an indicative filter/coalescer, there may be multiple of these units installed in parallel, as shown in **Figure 26**.



Figure 29: Indicative filter/coalescer

12.2 Gas Compression

Gas from the filter/coalescer vessel/s will be compressed to a typical pressure of 7500kPag via self-contained compressor packages. Each package will also be comprised of a fin-fan cooler to reduce the gas temperature after each stage of compression, interstage scrubber vessels to knock-out any water/lube oil condensed between compression stages in the fin fan cooler and a lubricating oil recirculation system. Each compressor package will its own control system. Key operating data from each compressor package will be available in the control room. **Figure 30** shows an indicative compressor package, including the compressor (right of the image) and fin fan cooler (left of the image) **Figure 31** shows an indicative compressor, and **Figure 32**, shows an indicative gas powered compressor drive engine, each compressor package contains one each of these units. There will be multiple of these compressor packages as shown in **Figure 26**.



Figure 30: Indicative Compressor Package, including compressor unit and fin fan cooler



Figure 31: Indicative compressor unit



Figure 32: Indicative gas compressor drive engine

12.3 Water Removal Downstream of Compressors

The cooled gas leaving the compressor packages will pass through a scrubber vessel where any condensed water / lube oil will be removed from the gas stream. This vertical vessel is provided with level instrumentation to automatically drain liquids from the system and a demister pad to reduce liquid carryover in mist form. **Figure 33** shows an indicative discharge scrubber.



Figure 33: Indicative discharge scrubber

The gas from the scrubber vessel will be sent to a Tri-Ethylene Glycol (TEG) dehydration unit, to remove moisture from the gas to meet the sales gas specifications. The key equipment items comprising the TEG dehydration unit are the contactor, reboiler, and TEG pumps. TEG liquid is constantly pumped through the contactor where water vapor transfers from the gas to the TEG liquid, the TEG liquid flows from the contactor to the reboiler where the water is removed from the TEG by heating the TEG above the boil point of water, the TEG is then cooled before returning to the contactor. **Figure 34** shows an indicative TEG gas dehydration unit.



Figure 34: Indicative TEG gas dehydration unit