Government of Saskatchewan

Disposal and Injection Well Requirements

Directive PNG008

December 2015

Revision 1.0

Governing Legislation:

Act: *The Oil and Gas Conservation Act*
Regulation: *The Oil and Gas Conservation Regulations, 2012*

Record of Change

Revision	Date	Author	Description
0	September, 2015	PNG	Draft
1.0	December, 2015	PNG	Revised and approved.

Contents

1. Introduction

This Directive sets out the requirements of the Saskatchewan Ministry of the Economy (ECON) for the licensing and operation of disposal and injection wells.

The purpose of this Directive is to detail the wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements for disposal and injection wells. Injection refers to injection of fluids into subsurface pools for the purpose of enhanced recovery and storage. Disposal refers to disposing of fluids into subsurface pools for purposes other than enhanced recovery or storage. The requirements in this Directive are designed to ensure hydraulic isolation of stored, injected or disposed fluids, and to protect groundwater and energy resources.

The following directives and guidelines are pertinent to this Directive:

- *Directive PNG001: Facility Licence Requirements*
- *Directive PNG005: Casing and Cementing Requirements*
- *Directive PNG009: Public Notice Requirements*
- *Guideline PNG029: Annulus Test Reporting Requirements*
- *Guideline PNG024: Reclassification and Recompletion*

Questions concerning the requirements set out in this document should be directed to the PNG support line at 1-855-219-9373.

1.1 Governing Legislation

The requirements outlined in this Directive are extracted from *The Oil and Gas Conservation Act (OGCA)* and *The Oil and Gas Conservation Regulations, 2012 (OGCR)*.

Sections 17 of the *OGCA* provide the minister with the authority to set requirements for disposal and injection. Regulations pertinent to the topics in this Directive are found in sections 53 and 54 of the *OGCR*. Licensees should consult these documents in conjunction with this Directive.

It is the responsibility of all operators, as specified in the legislation, to be aware of Ministry requirements and to ensure compliance with all requirements related to disposal and injection wells.

1.2 Definitions

Acid gas: gas that is separated during the treating of solution, or non-associated gas that contains hydrogen sulfide (H_2S), totally reduced sulfur compounds, and/or carbon dioxide (CO_2).

Casing inspection log: a log that determines the depth of anomalies into the well casing; distinguishes between external and internal corrosion; and detects holes, pits, perforations, metal loss and metal thickness in the casing.

Cement bond log: a log used to determine the quality of cement bonding between casing and rock formations.

Fracture gradient: the pressure gradient that, when applied to subsurface formations, causes the formations to fracture physically.

Hydraulic isolation log: a log that detects the flow of injected fluids behind the casing string.

Hydrocarbon-bearing formation: any defined or miscellaneous pool that is not a non-hydrocarbon-bearing formation.

Non-hydrocarbon-bearing formation: the common disposal pools shown in Appendix 1 which are routinely used for disposal purposes.

Packer isolation test: a pressure test of the tubing/casing annulus designed to evaluate the integrity of the casing, tubing and packer.

Potash waste brine: a waste brine produced from potash mining consisting primarily of Na, K and Cl, with lesser amounts of Ca, Mg, HCO_3 and SO_4, trace amounts of reagents used in the milling process, and leached components derived from wastes that are to be disposed in an approved Tailings Management Area.

Radioactive tracer log: a log that injects soluble radioactive material with a downhole injector at or near the maximum allowable injection pressure.

Produced salt water: water produced in association with crude oil or natural gas.

Step-rate injectivity test: an injectivity test that plots stabilized injection pressures against stabilized flow rates, at increasing flow rate steps sufficient to indicate either formation fracture, or the absence of fracture.

Waste processing facility: any facility that is constructed and operated for the purpose of containing, storing, handling, treating, processing, recovering, reusing, recycling, destroying or disposing of oil and gas waste.

2. Types of Disposal/Injection Wells

2.1 Routine Well Completion Types

The following well types are considered routine for purposes of well licensing using the Integrated Resource Information System (IRIS):

1) Disposal Well (Non-Project)

   Non-project disposal wells are used for the disposal of fluids where the well is not part of an active project approved by ECON (i.e., waterflood project, EOR project, etc.). Common disposal fluids include:

   a) produced salt water, which contains less than 10 parts per million (ppm) H_2S, associated with the recovery of hydrocarbons;

   b) water-based pigging fluids from cleaning of a collection or injection line, provided it

does not contain additional chemicals;

c) brine reject or backwash from water softeners associated with enhanced recovery; and

d) water from enhanced recovery schemes (can contain polymers or chemicals).

2.2 Non-Routine Well Completion Types

The following well types are considered non-routine for purposes of well licensing in IRIS:

1) Potash Waste Disposal Well

   a) Wells used for the disposal of potash waste brines recovered from potash operations.

2) Waste Disposal Well

   Most waste disposal wells are associated with an approved waste-processing facility regulated by ECON and/or industrial facility regulated by the Saskatchewan Ministry of Environment. There are four types of waste disposal wells:

   a) Wells used for disposal of oil-and-gas field non-hazardous waste fluids including produced water and specific common oil-and-gas field waste streams. Examples of non-hazardous oil-and-gas field wastes that may be disposed include boiler blowdown water, tank wash water, rig wash, spent glycols and drilling waste leachate.

   b) Wells used for disposal of non-oil-and-gas or industrial waste fluids generated from prescribed industries, such as the chemical and petrochemical refining industry, the mining and mineral processing industry, the electrical energy generating industry, the manufacturing industry, the forestry and forestry products industry, the construction industry, the transportation industry, the service industry, the waste management industry, and the geothermal industry.

   c) Wells associated with waste disposal cavern systems, which can receive hydrocarbon-based drilling wastes and other types of authorized wastes.

   d) Wells used for disposal of acid gas.

2.3 Well Completion Types Requiring Pre-Authorization

The following well completion types require pre-authorization in IRIS prior to submitting an application to licence or to recomplete or reclassify a well. Most of the well completions are project based, such as waterflood, EOR, or storage. Upon authorization, a licensee must specify the authorization number at the time of licensing for every well approved by that authorization.

1) Pressure Maintenance – Water Injection Well
2) Pressure Maintenance – Gas Injection Well
3) Air Injector (Combustion) Well
4) Alternating Pressure Maintenance – Water Injection/Air Injection
5) Alternating Pressure Maintenance – Water Injection/CO_2 Injection
6) Alternating Pressure Maintenance – Water Injection/Gas Injection

7) CO_2 Injector Well (These are wells used for the injection of CO_2 into a reservoir matrix for enhanced recovery operation.)
8) Commingled Disposal Well (Commingled disposal occurs when two or more formations are perforated and are being injected simultaneously through a common well casing or a single tubing string.)
9) Cyclic Oil/Steam Injector Well
10) Gas Storage (Cavern) Well
11) Gas Storage Well
12) Liquid Gas/NGLS Storage Well
13) Nitrogen Injector Well
14) Oxygen Injector Well
15) Permanent Oil/Steam Injector Well
16) Polymer Injector Well
17) Solvent Injector Well
18) Steam Injector Well (Permanent) (These are wells used for the injection of steam from potable water or recycled water into a reservoir matrix to stimulate reservoir production.)

3. Requirements for Non-Project Disposal Wells

Licences for non-project disposal wells can be applied for and approved through the licensing process in IRIS, without requiring pre-authorization from ECON. Subsections 3.1 and 3.2 are requirements the licensee must know and comply with when applying for a non-project disposal well licence. Appendix 2 shows the flow chart for decisions when licensing a non-project disposal well.

Reclassification to non-project disposal wells must be applied for in IRIS. Refer to this Directive and to Guideline PNG024.

3.1 Rights to Dispose

Licensees must obtain the right to dispose into the legal subdivision containing the pool receiving the disposal or injection fluids. Drainage unit and target area restrictions are not applied to disposal or injection wells. Three types of written consents are required:

1) Freehold land: written consent must be obtained from the mineral lessors and lessees, other than the applicant.
2) Disposed Crown land: written consent must be obtained from the holders of the Crown disposition, other than the applicant. Dispositions include oil and gas leases, licences or permits issued pursuant to *The Crown Minerals Act*.
3) Undisposed Crown land: the application will be processed as non-routine and a lease of space will be required.

3.2 Written Consent and Public Notification for Offsetting Owners

The following written consents are required from offsetting mineral owners for disposal wells:

1) For the disposal of salt water generated from oil-and- gas-field production:
    a) if the proposed disposal pool is in a non-hydrocarbon-bearing formation, written consent from offsetting mineral lessors and lessees is not required;
    b) if the disposal pool is considered to be hydrocarbon-bearing, the applicant must include written consent from:
        - any operators other than the applicant producing from the same pool or stratigraphic unit within an 800 m (oil) or 1.6 km (gas) radius of the well completion;
        - all freehold mineral lessors other than the applicant within an 800 m (oil) or 1.6 km (gas) radius of the well completion;
        - all lessees other than the applicant within an 800 m (oil) or 1.6 km (gas) radius of the well completion; and
        - the Ministry of the Economy if there are undisposed Crown lands within an 800 m (oil) or 1.6 km (gas) radius of the well completion (email consent requests to petlands@gov.sk.ca).

    If written consent from the aforementioned parties cannot be obtained, the Public Notice process must be conducted. Please refer to Directive PNG009 for information about consent letter requirements and the public notice process.

    ***Note**: It is the responsibility of the applicant to identify any potentially or directly affected parties outside of the minimum notification area and provide notification to these parties.*

2) For the disposal of wastes or other substances other than salt water generated from oil-and-gas-field production, the applicant must include written consent from:
    - all freehold mineral lessors other than the applicant within a 1.6 km radius of the well completion;
    - all lessees other than the applicant within a 1.6 km radius of the well completion;
    - the Ministry of the Economy if there are undisposed Crown land within 1.6 km of the well completion (email consent requests to petlands@gov.sk.ca).

    If written consent from the aforementioned parties cannot be obtained, the Public Notice process must be conducted.

4. Common Requirements for Disposal/Injection Wells

A licensee must ensure that all disposal/injection wells maintain wellbore integrity and hydraulic isolation of the disposal/injection fluids from other porous stratigraphic units. Any well that does not meet the requirements of this Directive may have its application denied or be subject to additional requirements.

A licensee must meet the following requirements:

1) Maximum wellhead injection pressure

   Disposal/Injection pressure must not exceed the formation fracture pressure. All disposal/injection wells will be subject to a maximum wellhead injection pressure (MWHIP). Refer to Appendix 3 for minimum requirements when calculating the maximum wellhead injection pressure. The formation fracture pressure may be determined by step-rate injectivity tests, in situ stress tests, or reliable offset data. A minimum safety factor of 10 per cent must be used, unless an alternative is adequately justified.

   A maximum wellhead injection report must be submitted within 30 days of completion on all disposal or injection wells. The report must include the maximum wellhead injection pressure and details as to how the value was determined, in accordance with the requirements laid out above.

2) Injection packer

   With the exception of previously approved disposal/injection wells, an injection packer is required for all disposal/injection wells. Unless otherwise approved, the injection packer must be set within disposal/injection pool or below the next porous interval above the disposal/injection pool at a location no more than five (5) metres true vertical depth (TVD) of:

   a) the top of the perforations;

   b) the casing seat in an open hole completion; or

   c) the top of the liner hanger in a liner completion.

3) The annulus must be filled with corrosion-inhibiting fluid and maintained at a positive pressure.

4) The portion of the casing exposed to disposal/injection fluids below the perforations must not exceed 25 m within the disposal/injection pool or within a shale formation directly below the disposal/injection pool. The portion of the wellbore below the injection interval must be plugged back in accordance with the Guideline PNG024.

5) An initial packer isolation test is required in accordance with Guideline PNG029.

6) The annulus and tubing pressures must be monitored and recorded on a minimum:

   a) daily basis for waste disposal wells and potash waste disposal wells; or

   b) monthly basis for other wells not included in (a) above.

   The monitoring data must be made available upon request by ECON within two (2) business days.

7) For potash waste disposal wells, annual formation pressure surveys must be conducted and submitted, unless otherwise stipulated by ECON. Refer to Appendix 4: Potash Waste Disposal Well for details.

5. Casing and Cementing Requirements

The well casing and cement must provide hydraulic isolation of the disposal contact intervals as well as protection of useable groundwater from aquifer cross-flow of the injected fluid, regardless of the fluid being disposed. Following is an additional requirement.

1) Waste Disposal Wells – Acid Gas

Acid-resistant cement must be used from total depth to above the disposal zone.

6. Logging Requirements

The following specifies the minimum logging requirements to evaluate hydraulic isolation of the disposal or injection contact intervals. All required logs must be submitted to ECON, accompanied by a detailed interpretation of the log against its specific objective performed by qualified personnel. Injection must not commence if log interpretation deems a lack of hydraulic isolation. In order to proceed, an application to repair a well must be submitted through IRIS and all work required must be completed to the satisfaction of the Ministry.

For existing wells, all porous stratigraphic units, in addition to the disposal pool, must be isolated by cement.

If production casing is not cemented to surface or cement returns to surface are not obtained and maintained during setting, a log must be run to locate the cement top.

1) Cement Bond Log

The cement bond log must demonstrate that hydraulic isolation exists between all porous stratigraphic units and provide a radial view of cement quality and identify lightweight cement quality. The following requirements must be met, unless otherwise specified by ECON.

- An initial full-length cement bond log must be run for non-horizontal disposal/injection wells.
- An initial cement bond log must be run from the top of the disposal/injection pool to the surface for horizontal wells.

2) Hydraulic Isolation Logs

- An initial hydraulic isolation log must be run on waste disposal or potash waste disposal wells.
- A subsequent hydraulic isolation log must be run every five (5) years on waste disposal wells.

Additional hydraulic isolation logs (i.e., temperature log, radioactive tracer log, etc.) may be required based on well-specific conditions, in addition to the required schedules above.

3) Casing Inspection Log

A full interpretation of the log must be submitted on a joint-by-joint basis that identifies anomalies, holes, pits, perforations, metal loss, wall thickness, and internal and external corrosion. The casing age, grade and collapse pressure of wells within the area of pressure influence should

also be considered at the time of the application, which may be a potential limiting factor to the MWHIP. As casing integrity may degrade with age, an appropriate safety factor must be applied.

- An initial full-length casing inspection log must be run on new and existing wells being converted for waste disposal or potash waste disposal.
- A subsequent casing inspection log must be run every ten (10) years on waste disposal wells.

Table 1 summarizes the logging requirements for disposal and injection wells. Appendix 5 provides the logging guidelines.

Table 1. Logging requirements.

	Types of Disposal/Injection Fluids					
	(1) Waste	(2) Potash Waste	(3) Produced Water	(4) CO_2 EOR	(5) Hydrocarbon or Other Gases[a]	(6) Steam
Logging Requirements - Initial						
Cement bond log	X	X	X	X	X	X
Hydraulic isolation log	X	X				
Casing inspection log (conversion)	X	X				
Casing inspection log (new)	X	X				
Logging Requirements - Subsequent						
Hydraulic isolation log (every 5 years)	X					
Casing inspection log (every 10 years)	X	X[b]				

a: Please refer to most recent edition of CSA Z341 for requirements in hydrocarbon storage wells.
b: Please see Appendix 4: Potash Waste Disposal Well for additional requirements.

7. Annulus Testing Requirements

Please refer to Guideline PNG029 for annulus testing requirements.

8. Injectivity Test Requirements

ECON will permit, without application, a maximum cumulative water injection of 500 m^3 in order to acquire the information to determine the maximum wellhead injection pressure (MWHIP) or injectivity.

A step-rate injectivity test can be used to determine the MWHIP or to confirm injectivity without fracturing the formation. Please note that step-rate test data from tests conducted after a hydraulic fracture stimulation may be inconclusive, and may not be acceptable for determining fracture pressure.

1) Procedure

The recommended standard procedure for carrying out a step-rate injectivity test is described in Appendix 6.

2) Conditions

The following conditions must be met when conducting a step-rate injectivity test or an analogous test to determine the maximum wellhead injection pressure or injectivity of a well.

a) The licensee must have the Right to Dispose/Inject.

b) The test period must not exceed 7 days.

c) The water injection volume must not exceed 500 m^3.

d) The injection packer must be set within 5 m of the true vertical depth of the disposal/injection perforations, or below the next porous interval above the injection pool.

e) If a new completion is required for the injection, an approval to recomplete must first be obtained from ECON prior to completing in a new pool. Please refer to the *Guideline PNG024: Reclassification and Recompletion*.

f) The test data and interpretation of the results must be submitted through IRIS within 30 days of test completion.

If the proposed testing method does not meet conditions above, an application to reclassify the well must be submitted through IRIS for approval prior to commencement of injection.

Other types of testing methods, such as in situ stress testing, mini-micro frac tests, or Diagnostic Facture Inject Test (DFIT), can be also used to determine the MWHIP, provided they comply with section 8(2) above.

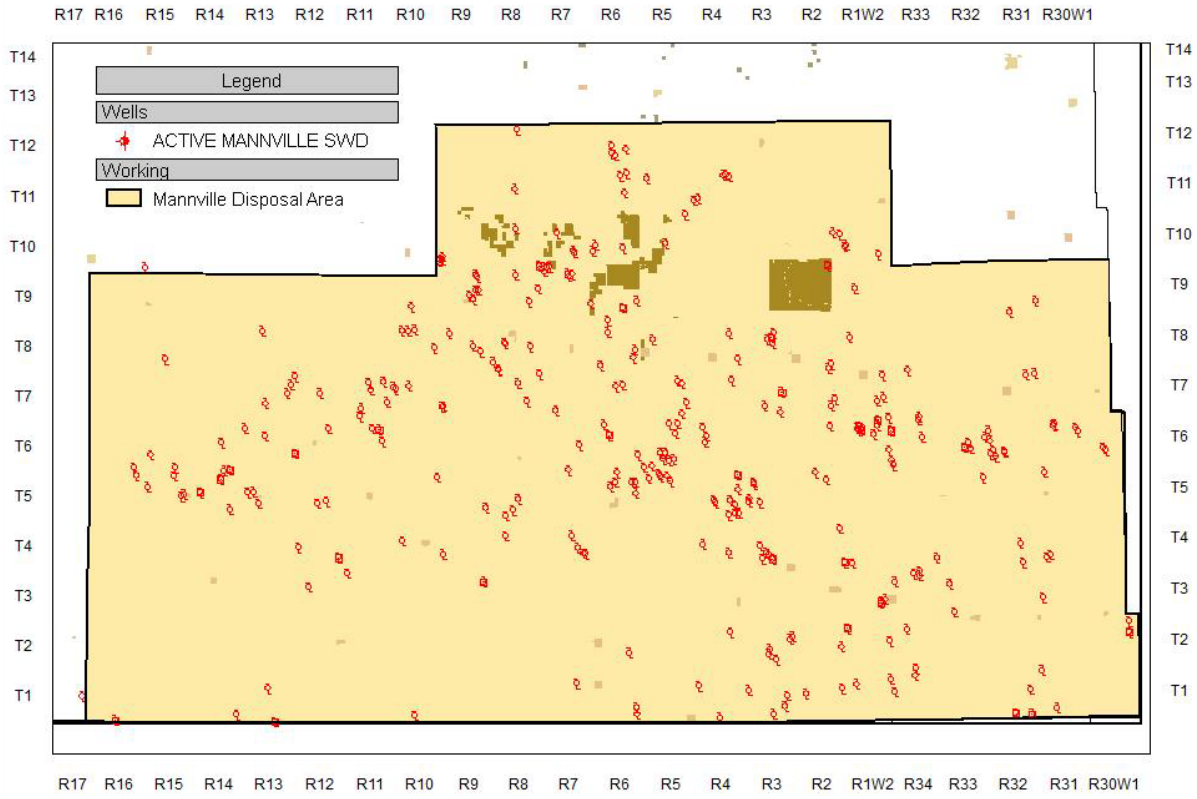
9. Surface Facilities

A separate facility application must be submitted to ECON if additional surface equipment is required for the disposal or injection well. For information on how to obtain a licence to construct and operate an upstream facility refer to Directive PNG001.

Appendix 1: Common Disposal Pools

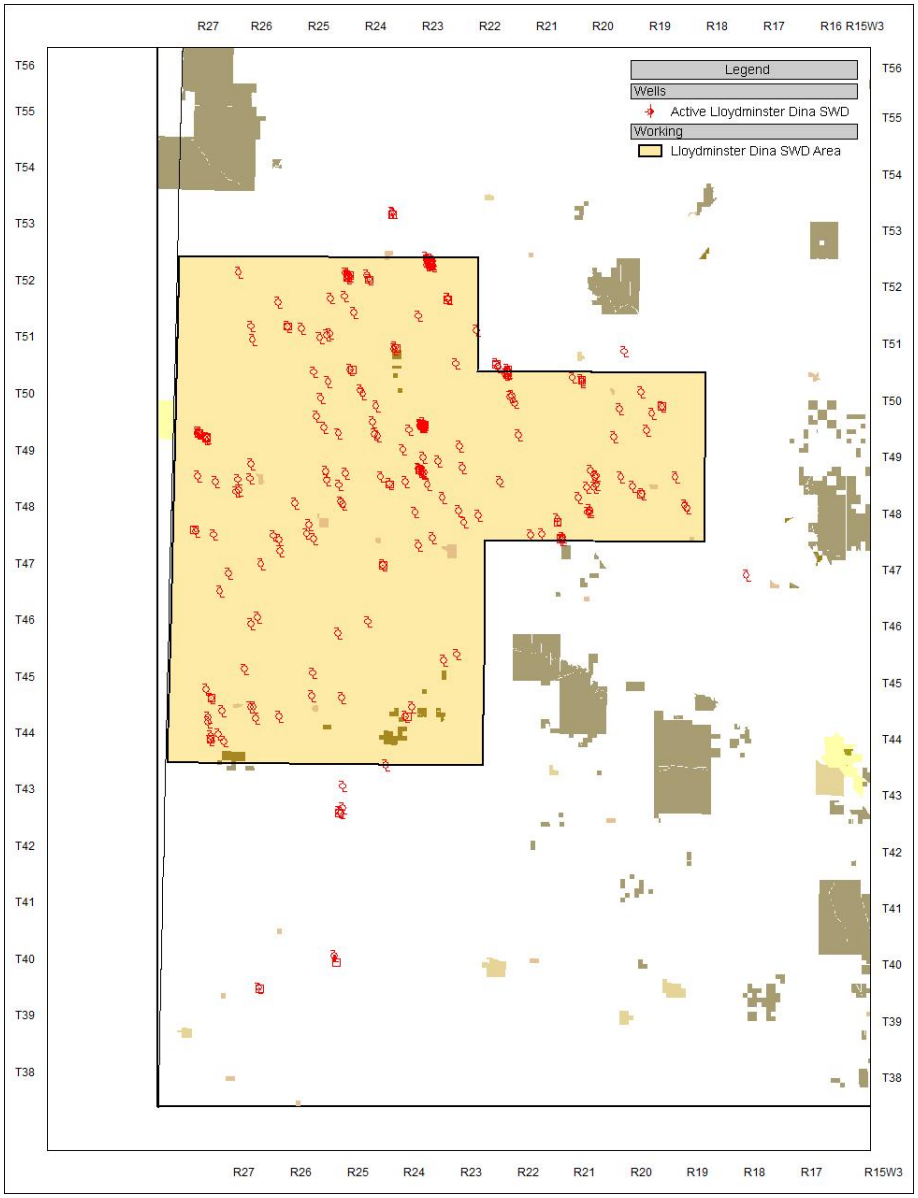
The areas where routinely approved disposal pools are located are: Mannville Sand in southeastern Saskatchewan and the Dina Sand in the Lloydminster District (Map 1 and Map 2, respectively).

Map 1 – Routinely Approved Mannville Disposal Pools in Southeastern Saskatchewan



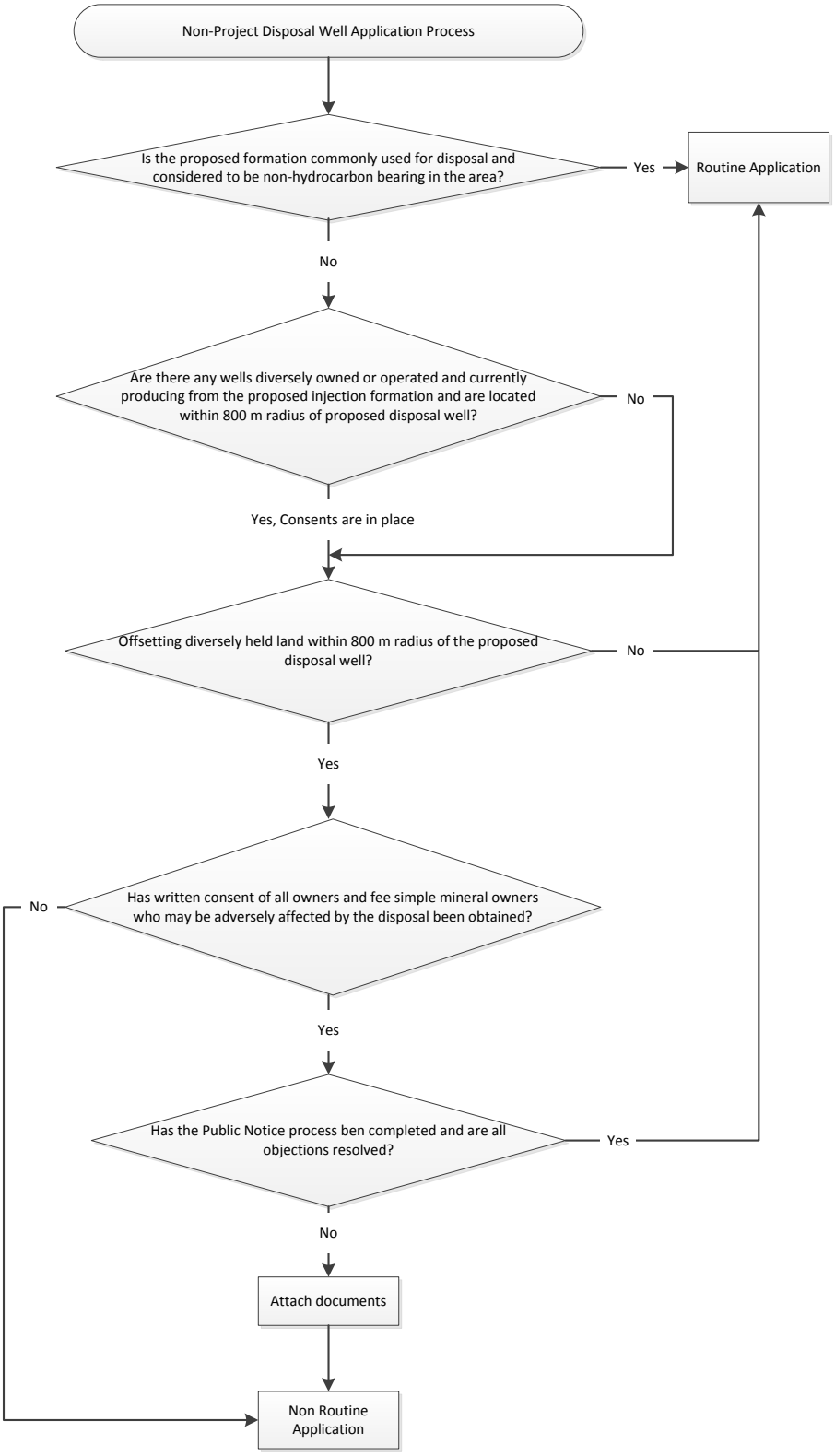
Common Mannville Disposal Area: Townships 01 to 09, Ranges 30W1M to 16W2M;
Townships 10 to 12, Ranges 01W2M to 09W2M.

Map 2 – Routinely Approved Dina Disposal Pools in the Lloydminster District



Common Dina Disposal Area: Townships 44 to 52, Ranges 23W3 to 28W3M;
Townships 48 to 50, Ranges 19W3M to 22W3M.

Appendix 2: Flow Chart Related to Applying for a Licence for a Non-Project Disposal Well



Appendix 3: Calculation of Maximum Wellhead Injection Pressure

The maximum wellhead injection pressure (MWHIP) must be limited to 90 per cent of the formation fracture pressure less the hydrostatic pressure of a column of disposal fluids in the wellbore, assuming the frictional pressure loss is negligible:

$$MWHIP = (P_{Fracture} \times 0.9) - P_{Fluid}$$

$P_{Fracture}$: Formation fracture pressure, in kPa, determined from procedures outlined in section 8 of this Directive.

P_{Fluid}: Hydrostatic pressure of disposal or injection fluid column in the wellbore, in kPa.

P_{Fluid} = depth to top of injection/disposal interval (mTVD) × disposal fluid gradient (kPa/m)

In the absence of local fracture pressure data, the MWHIP can be calculated using the following equation:

MWHIP = depth to top of injection/disposal interval (mTVD) × (18.1– disposal fluid gradient) (kPa/m)

Please note that variability in disposal fluid density, due to salinity or composition, requires use of a hydraulic wellbore gradient to calculate a conservative wellhead pressure value. ECON typically utilizes a value of 10.5 kPa/m as the disposal fluid gradient for calculating the maximum wellhead injection pressure. The well operator is responsible for adjusting the wellhead injection pressure to a lower value if a higher density/gradient value fluid is being disposed.

Appendix 4: Potash Waste Disposal Well

Potash waste disposal wells refer to wells used for the disposal of potash waste brines recovered from potash operations.

Casing and Cementing

The requirements set out in Directive PNG005 must be met. Potash waste disposal pool will require hydraulic isolation to ensure the waste brine does not migrate out of disposal pool.

Wellbore Integrity Logs

1) An initial full-length cement bond log and a hydraulic isolation log (temperature or radioactive tracer log) must be run to demonstrate hydraulic isolation;

2) An initial full-length casing inspection log must be run on the production casing string;

3) A full-length casing inspection log must be run on any wellbore conversions to ensure the casing is in good condition prior to injection;

4) A subsequent casing inspection log must be conducted every 10 years. If conducting a casing inspection log is not feasible, an alternative method including an enhanced annulus pressure test (consisting of holding a positive annulus pressure which exceeds the maximum operating pressure by 700 kPa for a minimum of 10 minutes, with a loss or buildup of less than 5% of the starting annulus pressure) will be considered upon application to and approval by ECON.

Operational Monitoring

1) The maximum wellhead injection pressure must not exceed the formation fracture pressure and is subject to calculating criteria in this Directive;

2) The annulus and tubing pressures must be monitored on a daily basis;

3) The annulus test must be conducted annually in accordance with PNG029.

4) Annual formation pressure survey must be conducted and submitted, unless otherwise stipulated by ECON.

Appendix 5: Logging Guidelines

The following are general guidelines that should be considered when running a hydraulic isolation, casing or cement integrity log. Certain aspects of these guidelines may not be appropriate in all situations. Regardless, logging company representatives should always be made aware of why logging is being conducted, to ensure that the configuration of programs and tools is appropriate for the specific well situation.

Hydraulic Isolation Logs

For all logs requiring injection (i.e., temperature and radioactive tracer), the following general design considerations apply.

- The well should be capable of accepting a stable injection rate, with sufficient fluid made available to conduct the entire logging program.
- Logging should be conducted with the well under normal injection conditions, preferably at or near the approved or requested maximum wellhead injection pressure.
- Wireline pressure control equipment that is capable of maintaining a casing pressure at least equal to the maximum injection pressure without significant pressure bleed-off while logging should be installed.
- The hydraulic isolation log must be run from the top of the injection interval to at least 200 m above the top of the zone of interest.

1) Temperature Logs

The temperature of the injected fluid should be adjusted to provide for a differential of at least 5°C at the injection zone. All temperature logs should be obtained logging down at a limit of 10 m per minute with the speed displayed on the log.

If conducting a temperature log on a horizontal well, an extended reach system may be needed.

Wells with or without prior injection (e.g., new, existing, extended shut-in, and converted wells)

The following procedures should be followed if no significant injection has occurred or the well has been shut in for an extended period where wellbore temperatures would be expected to be near geothermal.

- With the well shut in, run a baseline temperature log (logged down) and a baseline gamma ray log (logged up) from approximately 200 m above the top of the zone of interest to plug back total depth (PBTD).
- Inject a volume of fluid at or near the maximum operating pressure under normal injection conditions.
- With the well shut in, conduct four temperature runs (logged down) at intervals of at least a half hour to help identify storage areas. Be aware of boundary effects when analyzing for reservoir inflow.

The shut-in logs obtained should be presented as a composite overlay on the same axis for comparative purposes. Displays should enhance visual identification of anomalies by compressing the depth scale and expanding the temperature scale.

If running a temperature log on a steam injection well, it should be run a minimum of 200 m above the injection zone, full length if total depth (TD) is less than 200 m, or to the top of the horizontal section. Temperature logs should be run at a target downhole temperature in the range of 140°C to 160°C.

2) Radioactive Tracer Logs

Radioactive tracer logs can be effective for detecting near-wellbore flow behind casing. The tracer material should be compatible with the injection fluid to avoid density segregation or dropout of the tracer material. Logging tools should be centralized to avoid tracer ejection against the casing wall. The wellbore should be clear of tubing and packers over the zone of interest wherever practical, to avoid any radioactive tracer traps and to enhance interpretation.

***Note**: ECON does not recommend that radioactive tracer logs be performed on steam injection wells due to increased risks in handling radioactive materials in the vapour phase.*

The logging program should include the following basic components:

- The radioactive tracer material should be miscible with the fluid/gas being injected.
- With the well shut in, a baseline gamma ray (logged up) should be run from the TD or the PBTD to at least 200 m above the top of the zone of interest.
- With the well under a stable injection rate at or near the maximum injection pressure, a series of stationary tracer injections should be performed commencing above and continuing through the perforated interval until the bottom detector no longer detects the ejected slug. In cases of low injection rates, log-through procedures may be used in which the tracer ejections are not stationary.
- Injection of a slug of tracer above the perforations should be followed by four consecutive logging runs (i.e., storage passes) from the TD or the PBTD to 200 m above the zone of interest until the slug disappears or becomes stationary.
- It is recommended that stationary checks be performed above the packer to verify that the packer is holding (if applicable).

The results of the storage passes should be presented as a composite overlay.

3) Cement Bond Logs

All cement bond logs should be run after cement has cured; the timing of the logs is subject to the cement blend and downhole wellbore conditions.

a) General Design Considerations

- The well history should be researched to determine the cement type and anticipated placement, casing sizes and grades, and maximum fluid pressure exerted on the casing since the annular cement has cured.
- The logging tool should be selected and calibrated for the type of cement used.
- The logging tool should be properly centralized in the casing and be appropriately sized for the diameter casing used.

b) Well Preparation

- The casing should be cleared of any internal cement sheathing prior to logging.
- The wellbore fluid should be displaced with a consistent fluid of fresh water, drilling mud, or dead crude. Mud weights should be kept below 1200 kilograms per cubic metre to avoid attenuation problems.

c) Logging Procedures

- The main logging pass should, where possible, be run with the maximum historical fluid pressure on the casing to avoid micro-annulus effects.
- If possible, a section of free pipe should be logged as a baseline reference and for transit time / amplitude calibration.

4) Casing Inspection Logs

a) General Design Considerations

- The history of the well should be researched to determine all casing sizes, weights, and any activities that would influence the magnetic characteristics of the wellbore.

b) Well Preparation

- All tubing and mechanical items should be removed from the well.

Appendix 6: Recommended Procedures for Step-Rate Injectivity Test

The following procedure should be used as a guideline for performing a step-rate injectivity test[1].

1) Shut in the well or inject at a low rate until the bottom hole pressure has stabilized. This step will represent the first point of the pressure vs. rate plot.
2) Commence injection at a low rate until wellbore storage has been overcome and radial flow conditions are achieved. A stabilized pressure will indicate that radial flow conditions have been achieved. The time interval required to achieve a stabilized pressure must be applied to all subsequent injection periods.
3) Increase injection rate and continue to inject for the same time interval as the first injection period. Record the injection rate used and pressure at the end of this time interval.
4) Repeat step 3 at increasing injection rates until a minimum of five injection periods have been recorded. If formation fracture is achieved, two or more injection periods should be above the fracture pressure to clearly identify the inflection point in the pressure vs. rate plot.
5) Plot the stabilized pressures and injection rates. Draw a straight line through the data points. The point of inflection will indicate the formation fracture pressure, if achieved.

[1] Singh, P.K., Agarwal, R.G. and Jrase, L.D. (1987): Systematic design and analysis of step-rate tests to determine formation parting pressure; SPE paper 16798, presented at the 62nd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, Texas, September 27 to 30, 1987.