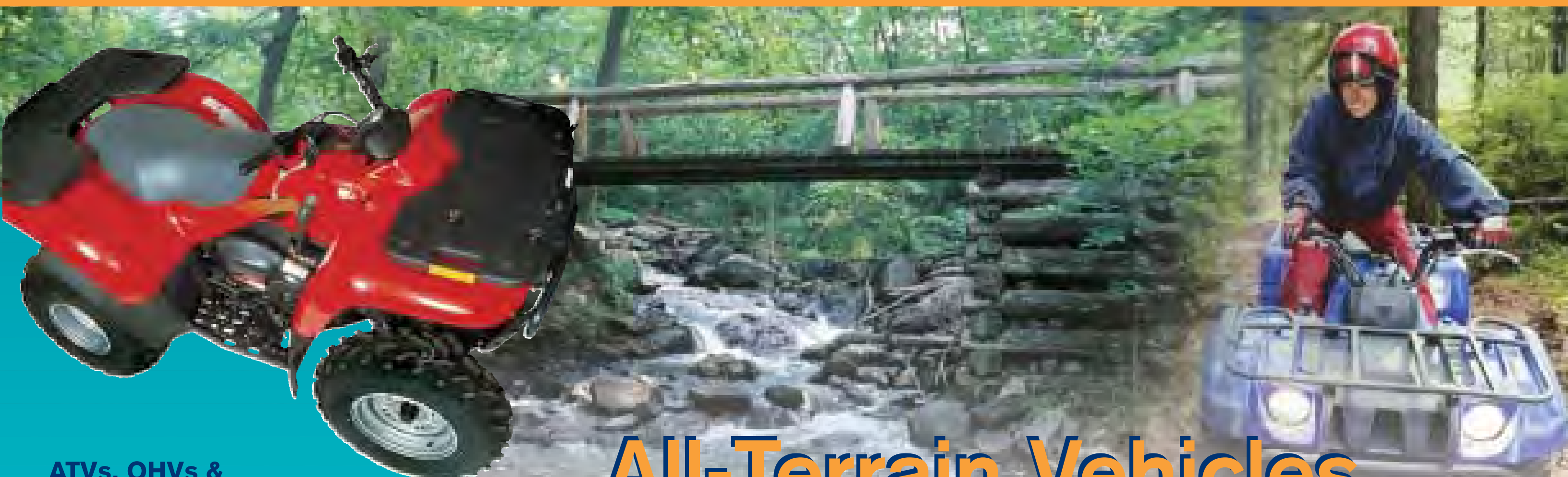
Fisheries and Oceans Canada | Pèches et Océans Canada



All-Terrain Vehicles, Fish Habitat, and You

Each year, more and more Canadians enjoy the use of all-terrain vehicles and off-highway vehicles (ATVs and OHVs). The wide variety of ATVs and OHVs include those motorized vehicles with common names such as 4x4s, quads, trikes, and off-road motorcycles. ATVs and OHVs provide a great way to travel, but operators should be aware of the potential impacts these vehicles can have on the environment. You can do your part by following these environmentally friendly riding practices that will allow you to enjoy off-roading activities while protecting our environment and aquatic ecosystems.

ATVs, OHVs & Fish Habitat

When crossing water bodies, riders often choose to cross at the shallowest point. Unfortunately this poses some of the greatest risks to fish and their habitats. These shallow crossing areas are also preferred by species such as walleye, trout, sucker and Arctic grayling as spawning sites. Gravel areas with shallow flowing water provide the eggs with clean and well-oxygenated water needed for their early growth. Driving over these areas can compact the gravel and cause siltation that may kill fish eggs and young fish, and at a minimum, will reduce the quality of the overall habitat.

The various plants in and along the shoreline of lakes and streams also provide important spawning, nursery and feeding habitat for many fish species. For example, northern pike rely on nearshore vegetation for spawning in the spring. Even though a creek, shoreline or wetland may be dry in the summer, it may provide important spawning and rearing habitat during high water.

Fish habitat will be protected if you follow the environmentally friendly guidelines in this fact sheet.

Riding

- Select your route in advance to avoid streams, rivers, lakes, marshes, beaches and wetlands, even if they are dry at the time of crossing. Many fish species and their eggs and fry are particularly vulnerable during the spring and fall seasons.
- Stay on established hard roads and trails. Braided trails can result in unnecessary and extensive environmental damage. ATV/OHV trails should be at least 30 metres away from all water bodies and wetlands. Try to maintain this “buffer zone” at all times.
- In general, try to avoid operating your vehicle during very wet conditions (such as after heavy rains and spring runoff) as the ground surface can be more easily damaged.
- Where the approach directs muddy water towards the water body, consider constructing cross-ditches along the trail. These ditches should be directed towards thick vegetation that would allow the soil and sediment to be filtered out before it reaches the water body.

Crossing Water Bodies with Steep Approaches

- Wherever possible, avoid crossing water bodies where the approaches are very steep. Steep banks are not only a safety hazard for the operator, they are also very vulnerable to soil erosion, especially during rainfall and runoff events. Plants help to stabilize banks and minimize bank erosion. Plants can be damaged or killed after repeated crossing attempts, leaving soil exposed to wind and rain. In some areas, particularly in northern

Watercrossing

- Do not drive your ATV or OHV up and down a stream channel or waterway at any time.
- Consider constructing bridges at water body crossings to minimize impacts to the water body and its fish habitat. (If bridges are the preferred option, be sure to acquire all regulatory approvals and permits before starting the work).
- If you cross a water body where there is no bridge, use crossings that others have used, or choose a location with a rocky bottom and low, stable banks. Minimise the number of times that the water body must be crossed, and cross slowly to avoid stirring up sediment that could drift downstream and smother spawning beds. Cross the water at right angles to the stream banks.
- Do not clear away the branches or brush in or around the water. Such plant and tree materials, even when dead, provide important habitat elements such as shade, predator protection, and rearing and feeding areas for fish. These features also help to maintain the stability of shorelines, stream banks and channels.

regions, plants are easily damaged and are slow to recover. In such cases, banks become ongoing sources of sediment.

Minimize Your Impact on the Slopes

- Do not remove vegetation on banks to gain access to upslope areas.
- Avoid water crossings where winching is necessary. Trees used for winching often become uprooted or damaged by cables and may die.
- Where winching is the only option, make sure that the anchor tree is big enough so that it is not pulled out of the ground or unnecessarily damaged by the winching. Use wide straps instead of cables or ropes, and place the winch strap as close to the base of the tree as possible to minimize damage.

Avoid Sensitive Areas

Some sensitive areas like bogs, fens, marshes, muskegs and small creeks may not contain fish, but are critical to a healthy watershed. These areas provide a water source and a filtration system which improves water quality. They also provide very important habitats to a wide diversity of species such as birds, small mammals and small aquatic organisms.

These areas often connect to other water bodies downstream where fish can live. If these sensitive areas are to be crossed, consider constructing a suitable crossing such as a bridge. A better option is to stay on high ground and avoid these areas altogether.

What Else Can I Do?

- Know the limits of your machine.
- Make sure ATV and OHV tires are maintained and capable of operating on the ground conditions on which you plan to ride.
- Ensure that your ATV or OHV does not have any fuel or oil leaks.
- Never wash your ATV or OHV in the water body since this can pollute the water.
- Take out what you took in. Make sure that you pick up all garbage (including broken fenders and mud flaps) and dispose properly.
- Respect signs that restrict ATV or OHV access.
- And last, but not least, consider the impacts that your ATV or OHV might have on the environment, and do your part to protect our waters and aquatic habitats.

Working Together to Protect Fish Habitat

The *Fisheries Act* plays a large role in ensuring the conservation and protection of our fisheries by providing for the protection of fish and fish habitat. Under this Act, no one may harmfully alter, disrupt or destroy fish habitat without an authorization from Fisheries and Oceans Canada. The Act prohibits the deposit of a deleterious (harmful) substance, such as pollutants and sediment, in waters frequented by fish.

This fact sheet does not constitute approval under the *Fisheries Act*, or under any other federal, provincial or municipal legislation or regulations that may be in force across different jurisdictions in Canada.

Help maintain the quality and quantity of fish habitat in our lakes and streams. For more advice on responsible ATV or OHV use, or any other activity in or near water, contact your local DFO district office.

For more information on the Fisheries Act, visit our website at: www.dfo-mpo.gc.ca/canwaters-eauxcan

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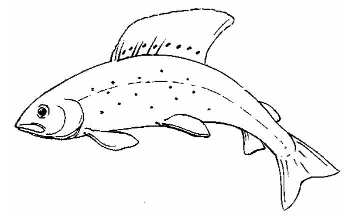
Fisheries and Oceans Pêches et Océans



DFO Protocol for Winter Water Withdrawal In the Northwest Territories

Rationale

In the Northwest Territories, winter activities such as access road construction, exploratory drilling and camp operations often require large amounts of water. Excessive amounts of water withdrawn from ice covered waterbodies or watercourses can lead to oxygen depletion, loss of over-wintering habitat and/or reductions in littoral habitat. The potential for such negative impacts to over-wintering fish and fish habitat has made winter water withdrawal a critical issue for the Department of Fisheries and Oceans (DFO) in the Northwest Territories. To address the issue of water withdrawal, and to provide standardized guidance to water users, including volume limits for certain water source types, DFO has developed this protocol in conjunction with industry and other regulators.

This protocol pertains to works and activities where a total water volume greater than or equal to (≥) $100m^3$ is required from any given waterbody or watercourse during one ice-covered period.

This protocol will **not** apply to the following:

- Winter water withdrawal from the Mackenzie River;
- Any other waterbody or watercourse that is exempted by DFO (i.e. Great Bear Lake, Great Slave Lake, Gordon Lake, and others as and when determined by DFO), and;
- Any waterbody (not including watercourses) from which less than $100m^3$ is to be withdrawn over the course of one ice-covered period.

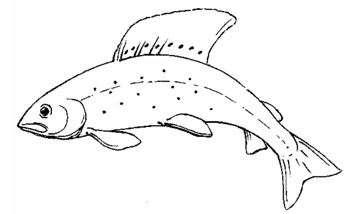
Water Withdrawal from Waterbodies:

For the purposes of this protocol, a **waterbody** is defined as any water-filled basin that is potential fish habitat. A waterbody is defined by the ordinary high water mark of the basin, and excludes connecting **watercourses** (see definition in **Water Withdrawal from Watercourses** below). In order to establish a winter water withdrawal limit for a given waterbody, the following criteria must be adhered to:

1. In one ice-covered season, total water withdrawal from a single waterbody is not to exceed 5% of the available water volume calculated using the appropriate maximum expected ice thickness provided in Table 1.
2. In cases where there are multiple users withdrawing water from a single waterbody, the total combined withdrawal volume is not to exceed 5% of the available water volume calculated using the appropriate maximum expected ice thickness provided in Table 1. Therefore, consistent and coordinated water source identification is essential.
3. Only waterbodies with maximum depths that are ≥1.5m deeper than their corresponding maximum expected ice thickness should be considered for water withdrawal (Table 1). Waterbodies with less than 1.5m of free water beneath the maximum ice are considered to be particularly vulnerable to the effects of water withdrawal.
4. Any waterbody with a maximum expected ice thickness (Table 1) that is greater than, or equal to, its maximum depth (as determined from a bathymetric survey) is exempt from the 5% maximum withdrawal limit.

To further mitigate the impacts of water withdrawal, water is to be removed from deep areas of waterbodies (>2m below the ice surface) wherever feasible, to avoid the removal of oxygenated surface waters that are critical to over-wintering fish. The littoral zone should be avoided as a water withdrawal location. Water intakes should also be properly screened with fine mesh of 2.54 mm (1/10") and have moderate intake velocities to prevent the entrainment of fish. Please refer to the *Freshwater Intake End-of-Pipe Fish Screen Guideline* (DFO, 1995) which is available upon request, or at the following internet address: www.dfo-mpo.gc.ca/Library/223669.pdf.

In order to determine the maximum water withdrawal volume from an ice-covered waterbody and thereby conform to this protocol, the following information must be provided to DFO for review and concurrence, prior to program commencement.



DFO Protocol for Winter Water Withdrawal In the Northwest Territories

Water Source Identification

1. Proposed primary and secondary access routes for all project activities, with proposed water source and crossing locations clearly identified on a map, with geographical coordinates (latitude/longitude and/or UTMs) included.
2. Documented watercourse connectivity (permanently flowing and/or seasonal) between the proposed water source and any other waterbody or watercourse.
3. Aerial photos or satellite imagery of the water sources if available.
4. Estimated total water withdrawal requirement for work or activity and estimated total water withdrawal per water source (in m^3).

Bathymetric Survey Results

1. For all waterbodies: One longitudinal transect, connecting the two farthest shorelines, is to be conducted regardless of waterbody size. **Note: a longitudinal transect may be straight or curved in order to accommodate the shape of a lake (see Figure 1).**
2. For waterbodies equal to or less than 1km in length: a minimum of one longitudinal transect and two perpendicular transects are to be conducted. Perpendicular transects should be evenly spaced on the longest longitudinal transect, dissecting the lake into thirds (Figure 1).
3. For lakes greater than 1km in length: a minimum of one longitudinal transect is to be conducted. Perpendicular transects (min. of 2) should be evenly spaced on the longest longitudinal transect at maximum intervals of 500m.
4. Additional transects should be run as required to include irregularities in waterbody shape such as fingers or bays (Figure 1).
5. All longitudinal and perpendicular transects are to be conducted using an accurate, continuous depth sounding methodology, such as open water echo sounding, that provides a continuous depth recording from one shore to the farthest opposing shore (Figure 1). Any alternative technology should be reviewed by DFO prior to implementing for bathymetric surveys.

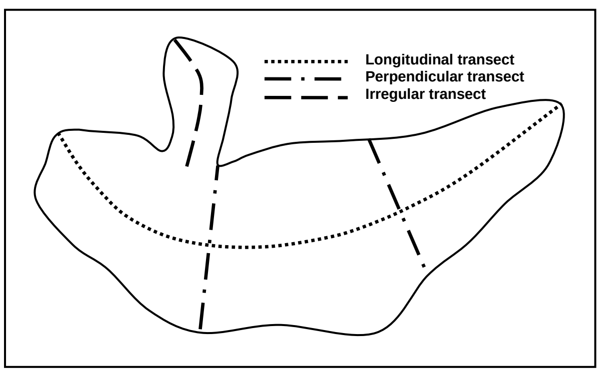
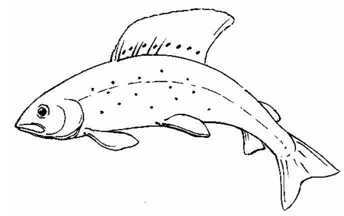


Figure 1. Minimum transect layout for a lake that is less than 1 km in length, with an irregularity.

Volume Calculations

1. Document the methods used to calculate surface area. If aerial photos or satellite imagery were used, provide the date (day/month/year) taken, as surface area may change depending on the time of year. If maps were used, provide the year that they were surveyed.
2. Detail the methods used to determine the total volume of free water, incorporating the relevant bathymetric information.
3. Calculate the available water volume under the ice using the appropriate maximum expected ice thickness, i.e. $\textit{Total Volume}_{lake} - \textit{Ice Volume}_{max\ thickness} = \textit{Available Water Volume}$ (see Table 1 for maximum ice thickness).
4. For programs where ice-chipping is used, the total ice volume to be removed from the waterbody should be converted to total liquid volume and incorporated into the estimate of total water withdrawal requirement per water source.



DFO Protocol for Winter Water Withdrawal In the Northwest Territories

Table 1. Maximum expected ice thickness, and corresponding water depth requirements, for different regions in the Northwest Territories.

Area	Maximum Expected Ice Thickness (m)	Minimum Waterbody depth Required for 5% Water Withdrawal (m)
Above the Tree Line	2.0	≥3.5
Below the Tree Line - North of Fort Simpson	1.5	≥3.0
Deh Cho –South of Fort Simpson	1.0	≥2.5

<u>Water Withdrawal from Watercourses:</u>

For the purposes of this protocol, a **watercourse** is defined as a channel through which water flows and is potential fish habitat. A watercourse is defined by the ordinary high water mark of the channel, and excludes connecting waterbodies or watercourses. In order to establish a winter water withdrawal limit for a given watercourse, the following criteria must be adhered to:

1. Total water withdrawal for all activities is not to exceed 5% of the instantaneous flow rate of a single watercourse at the time of withdrawal.
2. In cases where there are multiple users withdrawing water from a single watercourse, the total combined withdrawal rate is not to exceed 5% of the instantaneous flow rate at the time of withdrawal. Therefore, consistent and coordinated water source identification is essential.

To further mitigate the impacts from water withdrawal, water intakes should be properly screened with fine mesh of **2.54 mm (1/10")** and have moderate intake velocities to prevent the entrainment of fish. Please refer to the *Freshwater Intake End-of-Pipe Fish Screen Guideline* (DFO, 1995) which is available upon request, or at the following internet address: www.dfo-mpo.gc.ca/Library/223669.pdf.

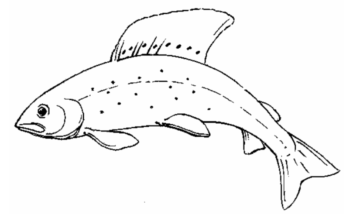
In order to determine the maximum water withdrawal rate from an ice-covered watercourse and thereby conform to this protocol, the following information must be provided to DFO for review and concurrence, prior to program commencement. DFO will only consider watercourses to be used as water sources if no suitable alternatives exist.

Water Source Identification

1. Proposed primary and secondary access routes for all project activities, with proposed water crossings and water source locations clearly identified on a map, with geographical coordinates (latitude/longitude and/or UTMs) included.
2. Aerial photos or satellite imagery of the water sources if available.
3. Estimated total water withdrawal requirement for work or activity, and estimated total water withdrawal per water source (in m^3).

Stream Survey Requirements

1. Location and date of survey (day, month, and year).
2. Photos of the stream location where withdrawal is to occur.
3. An accurate measurement of flow rate (to be confirmed immediately prior to water withdrawal commencing).
4. Stream survey should include; profile (minimum of ten evenly spaced points), depth, width, and flow rate.
5. Survey effort should reflect channel width: <2m wide, three vertical stations; 2-10m, 10 vertical stations; >10m, 20 vertical stations.
6. Pump specifications (type, model, horsepower, and max discharge rate).
7. Information on substrate type, in-water vegetation, riparian vegetation, and bank description is also requested.



DFO Protocol for Winter Water Withdrawal In the Northwest Territories

A brief project summary report documenting and confirming total water volume used per water source, withdrawal rates, flow rates per source and corresponding dates should be submitted to DFO within 60 days of project completion. Information should be provided in the following format (this information would also be useful as part of the project description):

Lake ID	**number and/or name**
Coordinates	**latitude and longitude and/or UTM coordinates**
Surface area	**in m^2**
Total Lake Volume	**in m^3**
Under Ice Volume	**in m^3 (based on max ice thickness for region)**
Max expected ice thickness value used	**in m**
Calculated 5% Withdrawal volume	**in m^3**
Total required water volume extracted	**in m^3**
Photograph of waterbody	
Bathymetric Map(s) of waterbody	

Any requests deviating from the above must be submitted to DFO and will be addressed on a site-specific basis.

Please note that adherence to this protocol does not release the proponent of the responsibility for obtaining any permits, licences or authorizations that may be required.

For more information contact DFO at (867) 669-4900.

Fisheries and Oceans Canada
Pêches et Océans Canada

Fish Habitat Management
Suite 101, 5204-50th Avenue
Yellowknife, Northwest Territories
X1A 1E2

Gestion de l'Habitat du Poisson
Suite 101 5204, 50e Avenu
Yellowknife (Territoires du Nord-Ouest)
X1A 1E2

Your file *Votre réference*

Our file *Notre réference*

August 14, 2008

Michael Peters
Canadian Assoc. of Petroleum Producers
211, 350-7th Ave. SW
Calgary, AB T2P 3N9

RE: Changes to DFO Protocol for Winter Water Withdrawal in the NWT

Dear Michael:

Fisheries and Oceans Canada (DFO), Western Arctic Area is in the process of revising the DFO Protocol for Winter Water Withdrawal in the NWT. The new protocol will likely not be available prior to this winter season. However, I would like to inform you of two changes to the protocol that are effective as of now. The changes to the conditions in the protocol are in bold.

1. In one ice-covered season, total water withdrawal from a single waterbody is not to exceed **10%** of the available volume using the appropriate maximum expected ice thickness provided in Table 1.

2. All longitudinal and perpendicular transects are to be conducted using an accurate, continuous depth sounding methodology, such as open water echo sounding **or ground penetrating radar (GPR)**, that provides a continuous depth recording from one shore to the farthest opposing shore (Figure 1). Any alternative technology should be reviewed by DFO prior to implementing for bathymetric surveys.

All other criteria/ conditions in the protocol remain the same. These changes, while still protective of fish and fish habitat, should provide more flexibility to industry during program development and operations.

If you have any questions, please contact me at (867) 669-4931.

Bruce Hanna
Habitat Biologist
Fish Habitat Management
Department of Fisheries and Oceans - Western Arctic Area

Canada

c.c:

Stephanie Carrol, Amanda Joynt - DFO
Adrian Paradis – MVLWB
Zabey Nevitt, Kathy Racher – WLWB
Rick Walburne, George Govier – SLWB
Bob Chalmers – EISC
Louie Porta – FJMC
Conrad Baetz – INAC
Reagan Stoddart – ILA
Johnny Edwards – GLWB
Liz Castaneda – NWT Water Board

Canadian Environmental Quality Guidelines

Canadian Environmental Quality Guidelines are now available online.

Go to "CEQG Online" to view all current guidelines for air, water, soil, sediment and tissue residue.

This essential reference guide for environmental resource managers also continues to be available as a comprehensive 2-binder system at the reduced price of $295 (plus shipping and handling and GST). To order the binder system click here.

When a new guideline is approved it will be posted to "CEQG Online" where users can print the ones they want.

Canadian Environmental Quality Guidelines provide nationally endorsed science based goals for the quality of atmospheric, aquatic, and terrestrial ecosystems. Users will find chemical-specific guideline fact sheets that summarize the key scientific information and rationale for each substance, detailed summary tables of recommended guidelines for the different media and resource uses, and the protocols used in developing the guidelines, along with their associated implementation guidance. Spreadsheet calculators for indices of Water Quality, Soil Quality and Sediment Quality are also included.

Canadian Environmental Quality Guidelines will provide you with:

- national benchmarks to assess potential or actual impairment of socially relevant resource uses
- the scientific basis for the development of site-specific criteria, guidelines, objectives or standards indicators for state-of-the-environment reporting
- science-based goals or performance indicators for regional, national, or international management strategies for toxic substances
- interim management objectives for persistent, bioaccumulative, and toxic substances to track progress toward their virtual elimination
- scientific tools for assessing risks associated with existing concentrations of persistent, bioaccumulative, and toxic substances in the ambient environment
- indicators of ecotoxicologically relevant concentrations of persistent, bioaccumulative, and toxic substances for the purpose of improving analytical detection and quantification capabilities
- tools to evaluate the effectiveness of point-source controls
- the scientific basis for environmental regulations scientific benchmarks or targets in the assessment and remediation of contaminated sites
- science-based assessments and tools for consideration in the development of Canada-wide standards under the Canada-wide Accord on Environmental Harmonization

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Environmental Guideline

for

Contaminated Site Remediation

November 2003

Guideline for Contaminated Site Remediation

Guideline for Contaminated Site Remediation

1 Introduction

In the Northwest Territories (NWT) and across Canada, contaminated sites pose a threat to human health and the environment. In some cases the concern may also be financial, because of the loss of equity and the cost of remediating the property.

The purpose of this guideline is to help you solve a contamination problem on your property by setting soil standards for site remediation. This guideline describes the process that is used to manage (e.g. identify, assess, remediate) contaminated or potentially contaminated sites on Commissioner's Land including private land within municipalities.

In the NWT the federal government has environmental jurisdiction over surface and groundwater. If contaminated water is encountered, Indian and Northern Affairs Canada must be consulted.

The NWT *Environmental Protection Act (EPA)* gives the Government of the Northwest Territories (GNWT) the authority to take all necessary measures to ensure the preservation, protection or enhancement of the environment, with the goal of sustainability and stewardship.

Section 2.2 of the *EPA* gives the Minister of Environment and Natural Resources (ENR) the authority to develop, coordinate, and administer these guidelines (see Appendix 1).

1.1 Definitions

CCME — The Canadian Council of Ministers of the Environment (CCME) is the major intergovernmental forum in Canada for discussion and joint action on environmental issues of national, international and global concern. The 14 member governments work as partners in developing nationally consistent environmental standards and practices. See Appendix 8 for contact information.

Closure Report — The final report prepared by the qualified person and provided to ENR following successful implementation of the Remedial Action Plan.

Commissioner's Land — Lands in the NWT that have been transferred by Order-in-Council to the GNWT. This includes highways and block land transfers. Most Commissioner's Land is located within municipalities.

Contaminant — Any noise, heat, vibration or substance and includes such other substance as the Minister may prescribe that, where discharged into the environment,
(a) endangers the health, safety or welfare of persons,
(b) interferes or is likely to interfere with normal enjoyment of life or property,
(c) endangers the health of animal life, or
(d) causes or is likely to cause damage to plant life or to property.

Contaminated Site	Areas of land, water, groundwater, or sediments that have levels of contaminants exceeding the remediation criteria. Contaminant sources can include on-site burial of wastes, small, frequent drips and spills, stockpiling and storage of materials, major spills, and releases during fires. Contamination may also be due to illegal dumping of contaminated soil. Contaminated sites may have short or long term consequences to the health of people or the quality of the environment.
Discharge	Includes any pumping, pouring, throwing, dumping, emitting, burning, spraying, spreading, leaking, spilling, or escaping.
Environment	Means the components of the Earth and includes (a) air, land and water, (b) all layers of the atmosphere, (c) all organic and inorganic matter and living organisms, and (d) the interacting natural systems that include components referred to in paragraphs (a) to (c).
Inspector	Means a person appointed under subsection 3(2) of the *EPA* and includes the Chief Environmental Protection Officer.
Qualified Person	A person who has an appropriate level of knowledge and experience in all aspects of contaminated site investigation, remediation and management.
Remedial Action Plan	A report that identifies Site-Specific Remedial Objectives for a site, identifies remedial options and outlines their feasibility, and recommends and describes a preferred conceptual remediation plan, a performance monitoring plan, and if appropriate, requirements for ongoing site management.
Remediation	The improvement of a contaminated site to prevent, minimize, or mitigate damage to human health or the environment. Remediation involves the development and application of a planned approach that removes, destroys, contains or otherwise reduces availability of contaminants to receptors of concern.
Remediation Criteria	The numerical limits or narrative statements pertaining to individual variables or substances in water, sediment or soil which are recommended to protect and maintain the specified uses of contaminated sites. When measurements taken at a contaminated site indicate that the remediation criteria are being exceeded, the need for remediation is indicated.

Additional definitions can be found in Appendix 2.

1.2 Roles and Responsibilities

1.2.1 Environment Division

The Environment Division (ED) of ENR is the main contact concerning remediation of contaminated sites on Commissioner's Land. ED determines the required level of remediation using the remediation criteria cited in this document. ED also reviews your remediation plan and monitors the progress of the project.

ED programs are applied primarily to Commissioner's Land, municipal lands or lands involving GNWT activities. The *EPA* provides the legislative authority. Contact ED for a listing of relevant legislation and guidelines or visit the web site at http://www.enr.gov.nt.ca/eps.

> ***ED will provide advice on remediation measures, but it is the sole responsibility of the polluter and landowner to provide adequate site remediation.***

1.2.2 Responsible Party

If the person responsible for a site is notified or otherwise has reason to believe that the site is potentially contaminated, that person shall immediately report the incident and ensure an appropriate evaluation of the potential adverse effects and risks is completed to determine what action, if any, is required under the *EPA* or this guideline.

These responsibilities can include the following:

- Exercising timeliness in all matters related to the contaminated site;
- Retaining a qualified person (see Section 1.1) to assess the site to determine the presence and extent of contamination;
- Developing a remedial action plan;
- Contacting affected or interested parties including: regional environmental health officer, Office of the Fire Marshal, local fire department, local government, landowner, affected adjacent landowners, Aboriginal claimant organization, or any other party as need be regarding health and safety concerns; and
- Remediating the contaminated site to acceptable levels.

1.2.3 Other Regulatory Agencies

Several external agencies may have to be involved with the management of a contaminated site due to their legislative responsibilities. Some of the other agencies that may be involved are:

1.2.4 Department of Transportation, GNWT

The Department of Transportation is responsible for administering the *Transportation of Dangerous Goods Act and Regulations* (NWT) including the transportation of contaminated soils (see Appendix 7).

1.2.5 Office of the Fire Marshal, GNWT

The Office of the Fire Marshal has authority over the storage, handling, use and processing of flammable and combustible liquids under the *Fire Prevention Act* and the withdrawal of tanks from service.

1.2.6 Office of the Chief Medical Officer, GNWT

Contaminated sites may impact residences or other buildings potentially affecting public health. The Office of the Chief Medical Officer or regional environmental health officers should be consulted regarding requirements under the *Public Health Act.*

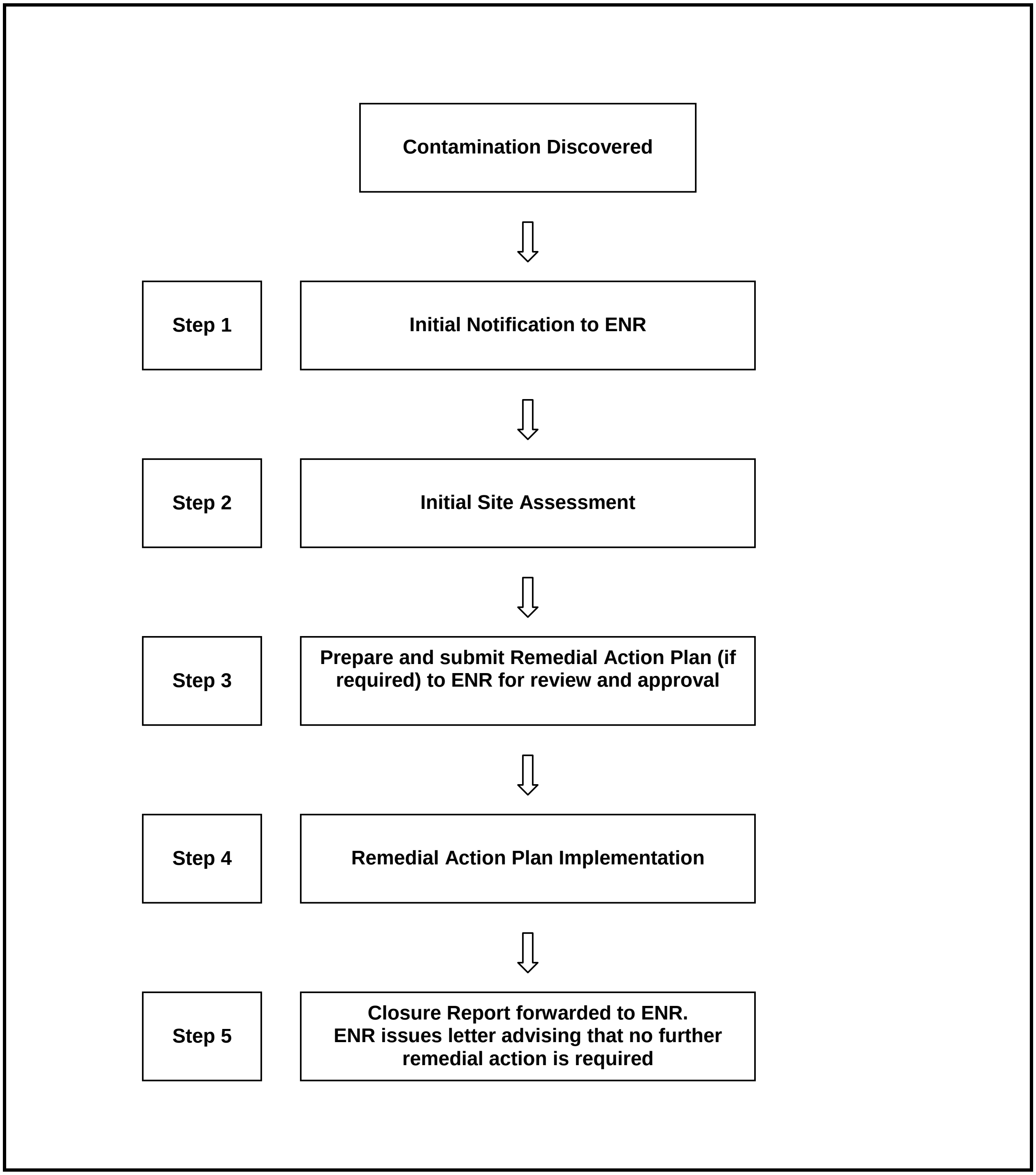
1.2.7 Local Government

The role of local governments is important in the management of contaminated sites. Firstly, clean up standards are often determined by how the property is designated under local government planning documents. Secondly, infrastructure (e.g., landfill site, community landfarm) may be utilized with the consent of the local government. Thirdly, the fire department may have to be called upon if a fire or public safety issue is identified.

2 Contaminated Site Management Process

The Contaminated Site Management Process consists of five steps from the time that contamination is discovered to final site remediation and closure. The following flow chart defines the steps in the overall management process.

Figure 1. Contaminated Site Management Process



2.1 Step 1 - Initial Notification

This step covers the initial time period following discovery of contamination and represents the normal initial notification to ENR. The occurrence may be a result of spills, accidents, investigations completed for the sale or refinancing of a property, or other situations that identify contamination impacts to the environment.

Section 5.1 of the *EPA* states that the owner, or person in charge, management or control of a contaminant discharged into the environment must:

- report the discharge to the NWT 24-Hour Spill Report Line at (867) 920-8130;
- take all reasonable measures to stop the discharge and repair any damage; and
- make a reasonable effort to notify affected public.

ENR will assess the significance of the reported discovery of the contamination by either a site visit by an ENR inspector or reviewing site assessment findings. Should ENR determine that the contamination presently, or in the future, poses a risk to human health or the environment, the inspector will require remedial action to be taken to rectify the situation and the responsible party to carry out such action. The responsible party may be required to complete the work in a specified time frame. ENR will consult with Office of the Chief Medical Officer or regional environmental health officers when exposure to indoor air contaminants originating from the release area is a concern.

If the inspector determines the problem cannot be solved with limited remedial action, ENR will instruct the responsible party to obtain the services of a qualified person (Step 2). If evidence of groundwater contamination or explosive vapours is present, or another party's property is affected, the services of a qualified person are mandatory. ENR will then consider the site a "contaminated site" until the management process has been completed.

In all cases, the responsible party is required to inform any affected parties about the contamination event and provide proof of such disclosure to ENR. Any issues not related to health and/or the environment that arises between the responsible party and affected parties are considered to be civil matters to be settled by the two parties outside of this management process.

2.2 Step 2 - Initial Site Assessment

During this step the qualified person conducts a site assessment to collect necessary technical information. Soil and groundwater effects must be assessed as well as potential effects on the surrounding population. A critical factor in a site assessment is completely defining and delineating the extent of the contamination in both soil and groundwater, even if it has crossed the source property boundary. Once the contamination plume is defined, it must remain defined. For instance, if monitoring data indicates that the plume is migrating beyond monitoring wells, then additional wells must be installed.

2.2.1 Environmental Site Assessment

Environmental Site Assessment (ESA) should identify the nature and extent of contaminants. A well-planned, comprehensive assessment will allow site managers to make informed decisions about potential remediation. There are three stages of phased investigation, depending on the size and complexity of the contaminated site, ranging from the general to the specific. The three phases of investigation are described below.

Phase I: Site Information Assessment

The purpose of the Phase I ESA is to identify actual and potential site contamination. At a minimum, the Phase I ESA must meet or exceed the Canadian Standards Association (CSA) Standard Z768-01, *Phase I Environmental Site Assessment*. See Appendix 8 for contact information.

In Phase I, the objective is to assemble all available historical and current information to help develop a field-testing program, should one be required. The work will begin by reviewing all data gathered for legal, transactional or environmental reasons (e.g., site classification, if already conducted) and supplementing this information as required.

The work frequently encompasses three broad aspects:

Facility Characteristics**.** A current and historical description of the site and its facilities is developed, particularly as it relates to the areas of concern like contaminant sources and discharge points. Visual inspections, facility records reviews and discussions with informed personnel are employed. In addition, above and below ground structures are reviewed (using blueprints, if available) as possible sources of contaminant migration. Prior site uses and surrounding land uses are also considered.

Contaminant Characteristics**.** Contaminants that may be present at the site are identified. Their quantities and concentrations are estimated by visual inspections, reviews of documentation and discussions with informed staff.

Physical Site Characteristics**.** The geology, hydrology and hydrogeology are examined using available data. The overall aim is to provide a more comprehensive description and understanding of the local site characteristics and to develop a current and historical description of the area.

The sources of information can include:

- aerial photographs;
- geology and groundwater reports;
- topographical, geological and other maps;
- ENR’s Hazardous Materials Spill Database; and
- previous site investigation reports.

The review will also include a site inspection and discussions with personnel and local residents informed about the site and its history and conditions. The site inspection will examine vegetation stress, key ecological receptors, leachate breakout and signs of contamination discharge. Surrounding land uses will also be considered. Drinking water sources and wells will be noted using published well records correlated to site observations. Proximity of the site to surface water bodies or sensitive habitats (e.g., wetlands) should also be identified.

Phase II: Reconnaissance Testing Program

The objective of the Phase II ESA is to confirm the presence and characterize the substances of concern at the site. The Phase II ESA must meet or exceed the CSA Standard Z769-00, *Phase II Environmental Site Assessment*.

Characterization of the contamination (i.e., degree, nature, estimated extent and media affected) and site conditions (i.e., geological, ecological, hydrogeological and hydrological) are necessary to develop a remedial action plan or to identify the need for more specific Phase III investigations. It also may be decided that no further action is required or that immediate action is needed. Further study may be necessary to determine risks to public health, safety or the environment. This may take the form of human health and ecological risk assessments using Phase II investigation data.

The Phase II sampling program should include the adoption of sampling procedures, quality assurance/quality control procedures and laboratory analytical protocols (see Appendix 6). In addition, preliminary environmental quality remediation criteria must be selected. See the CCME *Guidance Document on the Management of Contaminated Sites in Canada, April 1997* for further information.

Phase III: Detailed Testing Program

The results of the Phase II investigation will determine the need for a Phase III ESA. If sufficient data have been obtained at Phase II to characterize the site and/or the risk to human health and the environment, then the process may move directly to a remedial action plan (if it is required).

Alternatively, a Phase III detailed investigation may be necessary if the Phase II results indicate that significant contamination exists that will require remediation. This investigation will specifically address outstanding issues with a view to obtaining enough information to formulate a remedial action plan. The objectives of Phase III investigation are:

- to target and delineate the boundaries of identified contamination;
- to define, in greater detail, site conditions to identify all contaminant pathways, particularly with respect to possible risk assessment;
- to provide contaminant and other information necessary to finalize environmental quality remediation criteria or risk assessment; and
- to provide all other information required to develop a remedial action plan and input to specifications and tender documents.

Generally, the Phase III detailed testing program will concentrate on areas identified in the Phase II program and involve a similar systematic process of sampling and analysis, evaluation, conclusions and recommendations. However, a greater number of samples are usually collected and a smaller suite of chemical substances may be analyzed as the program converges on the environmental issues.

Once the environmental condition of the site has been assessed, the qualified person will compare it to applicable remediation criteria (numerical limits) in order to determine whether further investigative or remedial actions are required.

2.2.2 Land Use

The remediation criteria are presented in the context of four types of land use: agricultural, residential/parkland, commercial and industrial (as defined below). The criteria are considered generally protective of human and environmental health for specified uses of soil at contaminated sites. It is important to note that it is the *intended* future land use that governs the decision on the level of remediation performed at a site. Identifying the type of land use will help you assess the extent of human and ecological exposure to contaminants in the soil, and is essential for planning practical remediation programs. *The type of land found adjacent to the contaminated site may affect the remediation criteria levels that you have to follow.*

Agricultural	All uses of land where the activity is primarily related to the productive capability of the land or facility (e.g., greenhouse) and is agricultural in nature, or is related to the feeding and housing of animals such as livestock.
Residential/Parkland	All uses of land in which dwelling on a permanent, temporary or seasonal basis is the primary activity. Institutions, hospitals, schools, daycare and playgrounds are also indicated under this land use. This includes activity that is recreational in nature, and requires the natural or human designed capability of the land to sustain that activity. Residential/Parkland is often readily accessible to the public.
Commercial	All uses of land in which the primary activity is related to the buying, selling, or trading of merchandise or services.
Industrial	All land uses in which the primary activity is related to the production, manufacture or storage of materials. This does not include institutions (e.g., schools, hospitals, playgrounds). The public does not usually have uncontrolled access to this type of land.

2.2.3 Application of Remediation Criteria at Contaminated Sites

There are three basic approaches that may be utilized for the development of Site-Specific Remediation Objectives:

- **Tier 1** Direct adoption of remediation criteria (Criteria-based Approach)
- **Tier 2** Adoption of remediation criteria, with limited modifications (Modified Criteria Approach); and
- **Tier 3** The use of risk assessment (Risk-based Approach)

The criteria-based approach is designed to require fewer resources while providing a scientifically defensible basis for protection that is sufficiently flexible to account for certain site-specific factors. This approach is believed to provide an effective alternative to detailed risk assessment methods. The risk-based approach can be more complex and more costly, and is generally utilized when a criteria-based approach is not suitable for a site (e.g., large, complex industrial site).

Utilization of any of the three approaches is subject to the approval of ENR.

Tier 1 - Criteria-Based Approach

Under this approach, the remediation criteria selected for a site are adopted as the remediation objectives. In general, this method is most applicable where site conditions, receptors, and exposure pathways are similar with those assumed in the development of the criteria. Other factors that may bear weight on the decision to directly adopt criteria include cost, time, simplicity and technical considerations.

Table 1 below presents a summary of Tier 1 remediation criteria for petroleum hydrocarbons (PHC) in surface soil. Additional remediation criteria for other contaminants in soil (i.e., BTEX, metals, PAHs) can be found in Appendix 5.

Table 1. Summary of Tier 1 levels (mg/kg) for PHCs in surface soil.*

Land Use	Soil Texture	Fraction 1	Fraction 2	Fraction 3	Fraction 4
Agricultural	Coarse-grained soil	130	450 (150[a])	400	2800
	Fine-grained soil	260 (180[b])	900 (250[b])	800	5600
Residential/Parkland	Coarse-grained soil	30[c]	150[c]	400	2800
	Fine-grained soil	260 (180[b])	900 (250[b])	800	5600
Commercial	Coarse-grained soil	310 (230[a])	760 (150[a])	1700	3300
	Fine-grained soil	660 (180[b])	1500 (250[b])	2500	6600
Industrial	Coarse-grained soil	310 (230[a])	760 (150[a])	1700	3300
	Fine-grained soil	660 (180[b])	1500 (250[b])	2500	6600

* Additional Tier 1 levels for PHC soils are presented in the Appendix 3.
a = Where applicable, for protection against contaminated groundwater discharge to an adjacent surface water body.
b = Where applicable, for protection of potable groundwater.
c = Assumes contamination near residence with slab-on-grade construction.

Where a Tier 1 approach determines that applicable criteria are exceeded for the land use, specific remedial actions will be required unless a Tier 2 approach justifies the application of site-specific objectives and/or on-going site management.

Tier 2 - Modified-Criteria Approach

In certain circumstances, remediation criteria may be modified, within specified limits, and adopted for use as the remediation objective for the site. The acceptability of a Tier 2 approach for evaluation of off-site impacts may be subject to review by ED and the acceptance of other affected parties.

In general, the method may be utilized in situations where site conditions, land use, receptors or exposure pathways differ only slightly from those assumed in the development of the “generic” criteria. Specific guidance on situations in which modifications are allowed to the criteria, as well as details concerning implementation of the approach are provided in the *Guidance Manual for Developing Site-Specific Soil Quality Remediation Objectives for Contaminated Sites (CCME 1996).*

Tier 3 - Risk-Based Approach

In certain circumstances, the criteria-based approach may not be suitable for a site (e.g., pathways of exposure, target chemicals, receptors or other site characteristics differ from those used to develop the criteria-based approaches) and risk assessment procedures may be required in the development of Site-Specific Remediation Objectives. Site-specific objectives are developed from the results of the risk assessment to establish a concentration corresponding to an acceptable risk to human or ecological receptors.

Site-Specific Remediation Objectives for soil should be developed using risk assessment when there are:

- significant ecological concerns (e.g., critical or sensitive habitats for wildlife; rare, threatened or endangered species; parkland or ecological reserves; hunting or trapping resources);

- unacceptable data gaps. Examples include:
  - exposure conditions are particularly unpredictable or uncertain;
  - there is a lack of information about receptors;
  - there is a high degree of uncertainty about hazard levels;

- special site characteristics. For example:
  - the site is so large, or the estimated cost of remediation is so high, that a risk assessment is needed to provide a framework for site investigation and to set remediation priorities;
  - site conditions, receptors and/or exposure pathways differ significantly from those assumed in the derivation of criteria.

For example, Table 2 presents site-specific human health-based soil quality remediation objectives developed for arsenic in the Yellowknife area.

Table 2. Remediation Objectives (mg/kg) for Arsenic in Yellowknife area soils and sediment.*

Medium	Land Use		
	Residential	**Industrial**	**Boat Launch**
Soil	160	340	220
Sediment	N/A	N/A	150

* Further information and rationale is presented in Appendix 4.
N/A = Not Applicable.

If the developed site-specific remediation criteria are not exceeded, the qualified person may conclude that no further action is required and submit the evaluation report to ENR.

If site conditions exceed the applicable remediation criteria, the responsible party must submit the evaluation report to ENR and advise affected parties.

2.3 Step 3 - Preparation of a Remedial Action Plan

At this point the responsible party and qualified person will review the results of the site assessment and determine whether to remediate the site to the generic criteria or complete further work to develop site-specific remedial criteria using risk assessment approach.

Once the remediation criteria have been determined for the site, the qualified person must prepare a Remedial Action Plan (RAP) detailing the methodology for achieving these criteria as well as the proposed remedial action.

The RAP must:

- include contact information, including names of key personnel, consultants, contractors, telephone, mail, fax, and email contacts, physical addresses;
- summarize all data on contaminants identified during the site investigation(s);
- identify contaminants of concern and the media affected;
- identify the proposed clean up criteria and method(s) by which they have been derived;
- identify, quantify and characterize the materials to be treated/removed;
- summarize remedial options evaluated and the method used to select the preferred remedial strategy;
- describe the selected clean up method and its technical feasibility;
- detail an implementation plan, including a schedule;
- discuss control measures to minimize fugitive air emissions, surface water control, worker health and safety;
- identify the fate of residual contaminants; and
- identify remedial verification and long-term monitoring plans.

The final action in this step is to submit the RAP to ENR for approval.

2.4 Step 4 - Remedial Action Plan Implementation

The responsible party and the qualified person shall proceed with the approved RAP and submit monitoring reports to ENR on the pre-determined schedule.

The responsible party must advise ENR if activities deviate from the approved RAP. ENR will assess the significance of any deviations and respond accordingly. In situations where predictions included in the RAP fail to be achieved, the responsible party may be required to re-evaluate Step 3 and enhance the RAP.

2.5 Step 5 - Site Closure

When the responsible party and qualified person are satisfied that all the requirements of the RAP have been met, a closure report will be forwarded to ENR.

Upon receipt and acceptance of the closure report, ENR will conclude the management process by issuing a letter advising that no further remedial action is required.

3 Conclusion

This is a brief introduction to the contaminated site remediation process. This document is intended to inform you about some of the basic issues involved in contaminated site remediation. Once you have read this document and verified that you have a contaminated site, you must contact ED before proceeding though the Contaminated Site Management Process.

For more information, contact:

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4 References

Canadian Council of Ministers of the Environment (CCME). Canada-Wide Standards for Petroleum Hydrocarbons (PHC) in Soil, (2001).

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GNWT Resources, Wildlife, and Economic Development. Environmental Guideline for the General Management of Hazardous Waste, (1998).

Risklogic Scientific Services Inc. Determining Natural (Background) Arsenic Soil Concentrations in Yellowknife NWT, and Deriving Site-Specific Human Health-Based Remediation Objectives for Arsenic in the Yellowknife Area, (2002).

APPENDIX 1

Environmental Protection Act

The following is a subset of the *Environmental Protection Act,* R.S.N.W.T. 1988, c. E-3.

1. In this Act,

"contaminant" means any noise, heat, vibration or substance and includes such other substance as the Minister may prescribe that, where discharged into the environment,

(a) endangers the health, safety or welfare of persons,
(b) interferes or is likely to interfere with normal enjoyment of life or property,
(c) endangers the health of animal life, or
(d) causes or is likely to cause damage to plant life or to property;

"discharge" includes, but not so as to limit the meaning, any pumping, pouring, throwing, dumping, emitting, burning, spraying, spreading, leaking, spilling, or escaping;

"environment" means the components of the Earth and includes

(a) air, land and water,
(b) all layers of the atmosphere,
(c) all organic and inorganic matter and living organisms, and
(d) the interacting natural systems that include components referred to in paragraphs (a) to (c).

"inspector" means a person appointed under subsection 3(2) and includes the Chief Environmental Protection Officer.

2.2 The Minister may

(a) establish, operate and maintain stations to monitor the quality of the environment in the Territories;
(b) conduct research studies, conferences and training programs relating to contaminants and to the preservation, protection or enhancement of the environment;
(c) develop, co-ordinate and administer policies, standards, guidelines and codes of practice relating to the preservation, protection or enhancement of the environment;

3. (2) The Chief Environmental Protection Officer may appoint inspectors and shall specify in the appointment that powers that may be exercised and the duties that may be performed by the inspector under this Act and regulations.

5. (1) Subject to subsection (3), no person shall discharge or permit the discharge of a contaminant into the environment.

(2) REPEALED, R.S.N.W.T. 1988,c.117(Supp.),s.8.

(3) Subsection (1) does not apply where the person who discharged the contaminant or permitted the discharge of the contaminant establishes that

(a) the discharge is authorized by this Act or the regulations or by an order issued under this Act or the regulations;
(b) the contaminant has been used solely for domestic purposes and was discharged from within a dwelling house;
(c) the contaminant was discharged from the exhaust system of a vehicle;
(d) the discharge of the contaminant resulted from the burning of leaves, foliage, wood, crops or stubble for domestic or agricultural purposes;

(e) the discharge of the contaminant resulted from burning for land clearing or land grading;
(f) the discharge of the contaminant resulted from a fire set by a public official for habitat management of silviculture purposes;
(g) the contaminant was discharged for the purposes of combating a forest fire;
(h) the contaminant is a soil particle or grit discharged in the course of agriculture or horticulture; or
(i) the contaminant is a pesticide classified and labelled as "domestic" under the *Pest Control Products Regulations* (Canada).

(4) The exceptions set out in subsection (3) do not apply where a person discharges a contaminant that the inspector has reasonable grounds to believe is not usually associated with a discharge from the excepted activity.

5.1. Where a discharge of a contaminant into the environment in contravention of this Act or the regulations or the provisions of a permit or licence issued under this Act or the regulations occurs or a reasonable likelihood of such a discharge exists, every person causing or contributing to the discharge or increasing the likelihood of such a discharge, and the owner or the person in charge, management or control of the contaminant before its discharge or likely discharge, shall immediately:

(a) subject to any regulations, report the discharge or likely discharge to the person or office designated by the regulations;
(b) take all reasonable measures consistent with public safety to stop the discharge, repair any damage caused by the discharge and prevent or eliminate any danger to life, health, property or the environment that results or may be reasonably expected to result from the discharge or likely discharge; and
(c) make a reasonable effort to notify every member of the public who may be adversely affected by the discharge or likely discharge.

6. (1) Where an inspector believes on reasonable grounds that a discharge of a contaminant in contravention of this Act or the regulations or a provision of a permit or licence issued under this Act or the regulations has occurred or is occurring, the inspector may issue an order requiring any person causing or contributing to the discharge or the owner or the person in charge, management or control of the contaminant to stop the discharge by the date named in the order.

7. (1) Notwithstanding section 6, where a person discharges or permits the discharge of a contaminant into the environment, an inspector may order that person to repair or remedy any injury or damage to the environment that results from the discharge.

(2) Where a person fails or neglects to repair or remedy any injury or damage to the environment in accordance with an order made under subsection (1) or where immediate remedial measures are required to protect the environment, the Chief Environmental Protection Officer may cause to be carried out the measures that he or she considers necessary to repair or remedy an injury or damage to the environment that results from any discharge.

APPENDIX 2

Glossary

Accreditation	Formal recognition of the competence of an environmental analytical laboratory to carry out specified tests. Formal recognition is based on an evaluation of laboratory capability and performance; site inspections are utilized in the evaluation of capability.
Adverse Effect	An undesirable or harmful effect to an organism, indicated by some result such as mortality, altered food consumption, altered body and organ weights, altered enzyme concentrations or visible pathological changes.
Assess or Assessment	Investigations, monitoring, testing and other information-gathering activities to identify: (1) the existence, source, nature and extent of contamination resulting from a release into the environment of a hazardous material or chemical substance; and (2) the extent of danger to the public health, safety, welfare, and the environment. The term also includes studies, services, and investigations to plan, manage and direct assessment, and decommissioning and clean up actions.
Background Samples	Matrices minus the analytes of interest that are carried through all steps of the analytical procedure. They are used to provide a reference for determining whether environmental test sample results are significantly higher than "unpolluted" samples, which contain "zero", low, or acceptable levels of the analytes of interest. All matrices, sample containers, reagents, glassware, preparations, and instrumental analyses are included in the analysis of background samples.
Blank	The measured value obtained when a specified component of a sample is not present.
Chemical	Any element, compound, formulation or mixture of a substance that might enter the aquatic environment through spillage, application or discharge. Examples of chemicals that are applied to the environment are insecticides, herbicides, fungicides, and agents for treating oil spills.
Clean up	The removal of a chemical substance or hazardous material from the environment to prevent, minimize or mitigate damage to the public health, safety or welfare, or the environment that may result from the presence of the chemical substance or hazardous material. The clean up is carried out to attain specified clean up criteria.

Concentration	The amount of chemical or substance in a given environmental medium. Concentration is typically expressed in units such mg/L (in water), mg/kg (in soil or food) and mg/m3 (in air).
Criteria	Numerical standards that are established for concentrations of chemical parameters in various media to determine the acceptability of a site for a specific land use.
Environmental Analytical Laboratory	A laboratory engaged in the physical, chemical or biological measurements of either the receiving environment or discharges to the receiving environment.
Groundwater	All subsurface water that occurs beneath the water table in rocks and geologic formations that are fully saturated.
Guidelines	Statements outlining a method, procedure, process or numerical value which, while not mandatory, should be followed unless there is a good reason not to do so, and includes the numerical limits or narrative statements that are recommended to protect and maintain the specified uses of water, sediment, soil or air.
Hazardous Material	Is material including but not limited to, because of its quality, concentration, chemical composition, corrosive, flammable, reactive, toxic, infectious or radioactive characteristics, either separately or in combination with any substance or substances, that constitutes a present or potential threat to human health, safety or welfare, or to the environment, when improperly stored, treated, transported, disposed of, used or otherwise managed.
Migration	The movement of chemicals, bacteria and gases in flowing water or vapour in the subsurface.
Monitoring	The routine (e.g., daily, weekly, monthly, quarterly) checking of quality, or collection and reporting of information.
Objective	A numerical limit or narrative statement that has been established to protect and maintain a specified use of water, sediment or soil at a particular site by taking into account site-specific conditions. Objectives may be adopted directly from generic criteria or formulated to account for site-specific conditions.
Procedures	Methods used by a regulatory agency to establish environmental quality criteria. In contrast to an approach, a procedure does not include the philosophical basis of the process (e.g., guiding principles).
Quality Assurance/Quality Control (QA/QC)	Those procedures and controls designed to monitor the conduct of a study in order to ensure the quality of the data and the integrity of the study.

Receptor	A person or organism subjected to chemical exposure. An ecosystem component that is, or may be, adversely affected by a pollutant or other stress emanating from a contaminated site. Receptors may include biological or abiotic (e.g., air or water quality) components.
Risk	Risk is a measure of both the severity of health effects arising from exposure to a substance and the probability of its occurrence.
Risk Assessment	Procedure designed to determine the qualitative aspects of hazard identification and usually a quantitative determination of the level of risk based on deterministic or probabilistic techniques.
Screening	Rapid analysis to determine if further action (e.g., detailed analysis or clean up) is warranted.
Site-Specific Remedial Objectives	The objectives established for a specific site to be met by the implementation of a Remedial Action Plan and, if appropriate, ongoing site management.
Surface Water	Natural water bodies, such as rivers, streams, brooks and lakes, as well as artificial water courses, such as irrigation, industrial and navigational canals, in direct contact with the atmosphere.
Test Pit	A shallow pit made to characterize the subsurface.

APPENDIX 3

Remediation Criteria for Petroleum Hydrocarbons in Soil

The definition of Petroleum Hydrocarbons (PHC) describes a mixture of organic compounds found in and derived from geological substances such as oil, bitumen and coal. Petroleum products released into the environment, such as crude oil and jet fuel, typically contain thousands of compounds in varying proportions, composed predominantly of carbon and hydrogen, with minor amounts of nitrogen, sulphur and oxygen. PHC contamination in soils varies with the petroleum source, soil type, the composition, degree of processing (crude, blended or refined) and the extent of weathering caused by exposure to the environment. Such factors have complicated the assessment of the human and environmental health risks associated with PHC contamination in soil. This complicated assessment of risk has made it necessary to evaluate PHC as four fractions: F1, F2, F3, and F4. This is different from previous guidelines where PHC contamination in soil was assessed by one parameter - total petroleum hydrocarbons.

For the purposes of this document, PHC are subdivided according to specified ranges of equivalent carbon number (ECN). Each fraction is, in turn, made of subfractions. The subfractions have been described according to their relevant physical and chemical properties and toxicological characteristics. The divisions between the fractions have been established in consideration of analytical factors, physical and chemical properties, the expected relevance to biological response in soils and the ability to utilize the definitions and associated properties.

Fraction 1 (F1) encompasses the range of ECN from C6 to C10. It represents the volatile fraction of most hydrocarbon mixtures and consists of aromatic subfractions in the range >C8 to C10, as well as aliphatic subfractions in the ranges of C6 to C8 and >C8 to C10. Specific aromatic compounds falling within this fraction (i.e., benzene, toluene, ethylbenzene and xylene, BTEX) are normally managed separately and would therefore be subtracted from the aromatics in this fraction.

Fraction 2 (F2) encompasses the range of ECN from >C10 to C16. It represents the semi-volatile fraction and comprises aromatics and aliphatic subfractions in the ranges >C10 to C12 and >C12 to C16.

Fraction 3 (F3) encompasses the range of ECN from >C16 to C34. It includes both aromatics and aliphatics in the >C16 to C21 and >C21 to C34 ranges.

Fraction 4 (F4) encompasses the range of ECN from >C34 to C50+. PHC within this range often make up a significant proportion of crude oils and petroleum products, although the fraction is generally considered to be of low mobility, volatility and solubility.

Soil Texture Definition

Tier 1 and Tier 2 numerical values are prescribed for coarse-grained and fine-grained soils. Sufficient textural information should be obtained to permit classification of the soils as either coarse or fine. These are defined as follows:

Fine-grained soil means soil having a median grain size of <75 μm as defined by the American Society for Testing and Materials.

Coarse-grained soil means soil having a median grain size of >75 μm as defined by the American Society for Testing and Materials.

The clean up criteria are different for surface soil than for subsoils. For the purpose of this document **subsoil** is that soil which is 1.5 metres or deeper from the surface.

Tier 1 levels for PHC in soils are presented in the next five tables.

Table A1. Summary of Tier 1 levels (mg/kg) for PHCs in surface soil.*

Land Use	Soil Texture	Fraction 1	Fraction 2	Fraction 3	Fraction 4
Agricultural	Coarse-grained soil	130	450 (150[a])	400	2800
	Fine-grained soil	260 (180[b])	900 (250[b])	800	5600
Residential/Parkland	Coarse-grained soil	30[c]	150[c]	400	2800
	Fine-grained soil	260 (180[b])	900 (250[b])	800	5600
Commercial	Coarse-grained soil	310 (230[a])	760 (150[a])	1700	3300
	Fine-grained soil	660 (180[b])	1500 (250[b])	2500	6600
Industrial	Coarse-grained soil	310 (230 [a])	760 (150 [a])	1700	3300
	Fine-grained soil	660 (180 [b])	1500 (250 [b])	2500	6600

* Additional Tier 1 levels are presented in the next four tables.
a = Where applicable, for protection against contaminated groundwater discharge to an adjacent surface water body.
b = Where applicable, for protection of potable groundwater.
c = Assumes contamination near residence with slab-on-grade construction.

Table A2. Tier 1 levels (mg/kg soil) for PHCs for fine-grained surface soils.

Land Use	Exposure Pathways*	F1 (C6-C10)	F2 (>C10-C16)	F3 (>C16-C34)	F4 (>C34)
Agricultural	Soil Ingestion	15,000	8000	18,000	25,000
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor, 30 m offset)	2100	11,400	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Protection of GW for Livestock Watering[3]	TBD	TBD	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[4]	260	900	800	5600
	Eco Soil Ingestion	TBD	TBD	TBD	TBD
	Produce, Meat and Milk	NC	NC	NC	NC
Residential	Soil Ingestion	15,000	8000	18,000	25,000
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor)	940	5200	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[4]	260	900	800	5600
	Produce	NC	NC	NC	NC
Commercial	Soil Ingestion	RES	29,000	RES	RES
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor)	4600	25,000	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[4]	660	1500	2500	6600
Industrial	Soil Ingestion	RES	RES	NA	NA
	Dermal Contact	RES	RES	RES	NA
	Vapour Inhalation (indoor)	4600	25,000	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[4]	660	1500	2500	6600
	Offsite Migration	NA	NA	12,000	RES

* See *Canada-Wide Standards for Petroleum Hydrocarbons (PHC) in Soil: Technical Supplement* (CCME 2001) for descriptions of Exposure Pathways.
NA = Not applicable. Calculated value exceeds 1,000,000 mg/kg or pathway excluded.
RES = Residual PHC formation. Calculated value exceeds 30,000 mg/kg and solubility limit for PHC fraction.
NC = Not calculated. Insufficient data to allow derivation.
TBD = To be determined.
1 = Assumes site is underlain by groundwater of potable quality in sufficient yield (K of 10^{-4} cm/sec or greater).
2 = Assumes surface water body at 10 m from site.
3 = Generally applicable for this land use as related to use of dugouts and wells for supply of livestock water.
4 = Tier 1 values based primarily on laboratory bioassay response to fractions derived from fresh Federated Crude Oil and adjusted for textural factors.

Table A3. Tier 1 levels (mg/kg soil) for PHCs for coarse-grained surface soils.

Land Use	Exposure Pathways*	F1 (C6-C10)	F2 (>C10-C16)	F3 (>C16-C34)	F4 (>C34)
Agricultural	Soil Ingestion	15,000	8000	18,000	25,000
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor, 30 m offset)	200	1100	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Protection of GW for Livestock Watering[2]	9000	4000	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[3]	130	450	400	2800
	Eco Soil Ingestion	TBD	TBD	TBD	TBD
	Produce, Meat and Milk	NC	NC	NC	NC
Residential	Soil Ingestion	15,000	8000	18,000	25,000
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor, basement)	50	240	NA	NA
	Vapour Inhalation (indoor, slab-on-grade)	30	150	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[3]	130	450	400	2800
	Produce	NC	NC	NC	NC
Commercial	Soil Ingestion	RES	29,000	RES	RES
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor)	310	1700	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[3]	330	760	1700	3300
Industrial	Soil Ingestion	RES	RES	NA	NA
	Dermal Contact	RES	RES	RES	NA
	Vapour Inhalation (indoor)	310	1700	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Nutrient Cycling	TBD	TBD	TBD	TBD
	Eco Soil Contact[3]	330	760	1700	3300
	Offsite Migration	NA	NA	RES	RES

* See *Canada-Wide Standards for Petroleum Hydrocarbons (PHC) in Soil: Technical Supplement* (CCME 2001) for descriptions of Exposure Pathways.
NA = Not applicable
RES = Residual PHC formation. Calculated value exceeds 30,000 mg/kg and solubility limit for PHC fraction.
NC = Not calculated. Insufficient data to allow derivation.
TBD = To be determined.
1 = Assumes surface water body at 10 m from site.
2 = Includes use of dugouts and wells for supply of livestock water.
3 = Tier 1 values based mainly on laboratory bioassay response to fractions derived from fresh Federated Crude Oil.

Table A4. Generic levels for PHCs in fine-grained subsoil (>1.5 m depth).

Land Use	Exposure Pathways*	F1 (C6- C10)	F2 (>C10-C16)	F3 (>C16-C34)	F4 (>C34)
Agricultural	Soil Ingestion	RES	RES	RES	RES
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor, 30 m offset)	2100	11,400	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Protection of GW for Livestock Watering[3]	TBD	TBD	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[4]	750	2200	3500	10,000
	Eco Soil Ingestion	TBD	TBD	TBD	TBD
	Produce, Meat and Milk	NA	NA	NA	NA
Residential	Soil Ingestion	RES	RES	RES	RES
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor: basement, slab)	(940, 990)	(5200, 5500)	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[4]	750	2200	3500	10,000
	Produce	NA	NA	NA	NA
Commercial	Soil Ingestion	RES	RES	RES	RES
	Dermal Contact	NA	RES	NA	NA
	Vapour Inhalation (indoor)	4800	26,000	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[4]	1000	3000	5000	10,000
Industrial	Soil Ingestion	NA	NA	NA	NA
	Dermal Contact	NA	NA	NA	NA
	Vapour Inhalation (indoor)	4800	26,000	NA	NA
	Protection of Potable GW[1]	180	250	NA	NA
	Protection of GW for Aquatic Life[2]	TBD	TBD	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[4]	1000	3000	5000	10,000
	Offsite Migration	NA	NA	NA	NA

* See *Canada-Wide Standards for Petroleum Hydrocarbons (PHC) in Soil: Technical Supplement* (CCME 2001) for descriptions of Exposure Pathways.
NA = Not applicable
RES = Residual PHC formation. Calculated value exceeds 30,000 mg/kg and solubility limit for PHC fraction.
NC = Not calculated. Insufficient data to allow derivation.
TBD = To be determined.
1 = Assumes site is underlain by groundwater of potable quality in sufficient yield (K of 10^{-4} cm/sec or greater).
2 = Assumes surface water body at 10 m from site.
3 = Generally applicable for this land use as related to use of dugouts and wells for supply of livestock water.
4 = Tier 1 values based primarily on laboratory bioassay response to fractions derived from fresh Federated Crude Oil and adjusted for texture, depth factors and other physical hazard considerations.

Table A5. Generic levels for PHC in coarse-grained subsoil (>1.5 m depth).

Land Use	Exposure Pathways*	F1 (C6-C10)	F2 (>C10-C16)	F3 (>C16-C34)	F4 (>C34)
Agricultural	Soil Ingestion	RES	RES	RES	RES
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor, 30 m offset)	200	1100	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Protection of GW for Livestock Watering[2]	9000	4000	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[3]	350	1500	2500	10,000
	Produce, Meat and Milk	NA	NA	NA	NA
Residential	Soil Ingestion	RES	RES	RES	RES
	Dermal Contact	RES	RES	RES	RES
	Vapour Inhalation (indoor, basement)	50	240	NA	NA
	Vapour Inhalation (indoor, slab-on-grade)	40	190	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[3]	350	1500	2500	10,000
	Produce	NA	NA	NA	NA
Commercial	Soil Ingestion	RES	RES	RES	RES
	Dermal Contact	NA	RES	NA	NA
	Vapour Inhalation (indoor)	340	1800	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[3]	700	2000	3500	10,000
Industrial	Soil Ingestion	NA	NA	NA	NA
	Dermal Contact	NA	NA	NA	NA
	Vapour Inhalation (indoor)	340	1800	NA	NA
	Protection of Potable GW	860	1200	NA	NA
	Protection of GW for Aquatic Life[1]	230	150	NA	NA
	Nutrient Cycling	NA	NA	NA	NA
	Eco Soil Contact[3]	700	2000	3500	10,000
	Offsite Migration	NA	NA	NA	NA

* See *Canada-Wide Standards for Petroleum Hydrocarbons (PHC) in Soil: Technical Supplement* (CCME 2001) for descriptions of Exposure Pathways.
NA = Not applicable
RES = Residual PHC formation. Calculated value exceeds 30,000 mg/kg and solubility limit for PHC fraction.
NC = Not calculated. Insufficient data to allow derivation.
TBD = To be determined.
1 = Assumes surface water body at 10 m from site.
2 = Includes use of dugouts and wells for supply of livestock water.
3 = Tier 1 values based primarily on laboratory bioassay response to fractions derived from fresh Federated Crude Oil and adjusted for depth factors and other physical hazard considerations.

APPENDIX 4

Remediation Criteria for Arsenic in the Yellowknife Area Soils and Sediment

The national soil guideline derived for arsenic by CCME is based on an assumed background (natural) arsenic soil concentration of 10 ppm, and the target incremental human health risk level of 1 in 1 million, which resulted in a national guideline of 12 ppm. However, CCME recognizes that inorganic elements vary significantly in natural concentration from one region to another. Also, CCME recognizes that the frequency, duration and intensity of use of a particular contaminated site or area may depart significantly from the assumptions used to derive the national guideline. Finally, although the CCME national guideline is based on a hypothetical risk level of 1 in 1 million, a *de minimis* risk level of 1 in 100,000 or lower is considered by Health Canada to be "essentially negligible." Following methods prescribed by CCME, to account for these site-specific factors and policy considerations, site-specific human health-based soil quality remediation objectives were derived for soil-borne and sediment-borne inorganic arsenic contamination in the Yellowknife area.

Based on data available from the Geologic Survey of Canada, the Environmental Sciences Group of the Royal Military College of Canada and data provided by Miramar Mining Ltd. (Con Mine), the average natural background concentration of arsenic in and around Yellowknife was determined to be 150 ppm, with a reasonable upper limit of normal concentration (the 90th percentile value of the distribution of available data) of about 300 ppm.

Site-specific human health-based soil quality remediation objectives were derived following CCME procedures for residential and industrial land uses, as well as for non-residential, publicly-accessible areas (i.e., local public boat launch). Accounting for the observed background arsenic concentrations in soil, considering a 1 in 100,000 *de minimis* cancer risk level, and considering the limitations on land use (i.e., impacts on the frequency, duration and intensity of site use) presented by the local climate, the remediation objectives presented in Table A6 have been adopted.

Table A6. Remediation Objectives (mg/kg) for Arsenic in Yellowknife area soils and sediment.

Medium	Land Use		
	Residential	**Industrial**	**Boat Launch**
Soil	160	340	220
Sediment	N/A	N/A	150

N/A = Not Applicable.

The remediation objective for residential properties assumes that the yard soil is accessible for exposure for 5 months of the year. This objective should also be applied to playgrounds and urban parks within the City limits where children may frequent on a regular and routine basis for daily play. The remediation objective for industrial lands assumes that little or no public access is available, and the primary receptor is a worker on the site. The soil quality objective for sites, developed for a specific site assumes that a person is present on the site for 2 hours per day, every day throughout July and August. The proposed sediment quality objective also assumes that a person is wading bare foot each day throughout July and August.

APPENDIX 5

Table A7. Remediation Criteria for other Contaminants in soil ($mg.kg^{-1}$)

Substance	Land Use			
	Agricultural	Residential/ Parkland	Commercial	Industrial
General Parameters				
Conductivity [dS/m]	2	2	4	4
pH	6 to 8	6 to 8	6 to 8	6 to 8
Sodium adsorption ratio	5	5	12	12
Inorganic Parameters				
Antimony	20	20	40	40
Arsenic (inorganic)*	12	12	12	12
Barium	750	500	2000	2000
Beryllium	4	4	8	8
Boron (hot water soluble)	2	-	-	-
Cadmium	1.4	10	22	22
Chromium				
Total chromium	64	64	87	87
Hexavalent chromium (VI)	0.4	0.4	1.4	1.4
Cobalt	40	50	300	300
Copper	63	63	91	91
Cyanide (free)	0.9	0.9	8.0	8.0
Fluoride (total)	200	400	2000	2000
Lead	70	140	260	600
Mercury (inorganic)	6.6	6.6	24	50
Molybdenum	5	10	40	40
Nickel	50	50	50	50
Selenium	1	1	3.9	3.9
Silver	20	20	40	40
Sulphur (elemental)	500	-	-	-
Thallium	1	1	1	1
Tin	5	50	300	300
Vanadium	130	130	130	130
Zinc	200	200	360	360
Monocyclic Aromatic Hydrocarbons				
Benzene	0.05	0.5	5	5
Monochlorobenzene	0.1	1	10	10
l,2-Dichlorobenzene	0.1	1	10	10
l,3-Dichlorobenzene	0.1	1	10	10
l,4-Dichlorobenzene	0.1	1	10	10
Ethylbenzene	0.1	1.2	20	20
Styrene	0.1	5	50	50
Toluene	0.1	0.8	0.8	0.8
Xylene	0.1	1	17	20
Phenolic Compounds				
Chlorophenols[a] (each)	0.05	0.5	5	5
Nonchlorinated[b] (each)	0.1	1	10	10
Pentachlorophenol (PCP)	7.6	7.6	7.6	7.6
Phenol	3.8	3.8	3.8	3.8

Table 1. Continued.

Polycyclic Aromatic Hydrocarbons (PAHs)				
Benzo(*a*)anthracene	0.1	1	10	10
Benzo(*b*)fluoranthene	0.1	1	10	10
Benzo(*k*)fluoranthene	0.1	1	10	10
Benzo(*a*)pyrene	0.1	0.7	0.7	0.7
Dibenz(*a,h*)anthracene	0.1	1	10	10
Indeno(I,2,3-c,d)pyrene	0.1	1	10	10
Naphthalene	0.1	0.6	22	22
Phenanthrene	0.1	5	50	50
Pyrene	0.1	10	100	100
Chlorinated Hydrocarbons				
Chlorinated aliphatics[c] (each)	0.1	5	50	50
Chlorobenzenes[d] (each)	0.05	2	10	10
DDT (total)	0.7	0.7	12	12
Hexachlorobenzene	0.05	2	10	10
Hexachlorocyclohexane (Lindane)	0.01	-	-	-
PCDDs and PCDFs[e] (dioxins and furans)	4 ng TEQ.kg^{-1}	4 ng TEQ.kg^{-1}	4 ng TEQ.kg^{-1}	4 ng TEQ.kg^{-1}
Polychlorinated biphenyls (PCBs)	0.5	1.3	33	33
Tetrachloroethylene (PCE)	0.1	0.2	0.5	0.6
Trichloroethylene (TCE)	0.1	3	31	31
Miscellaneous Organic Parameters				
Ethylene glycol	960	960	960	960
Nonchlorinated aliphatics (each)	0.3	-	-	-
Phthalic acid esters (each)	30	-	-	-
Quinoline	0.1	-	-	-
Thiophene	0.1	-	-	-

Notes:

- = Value not established.

* See Appendix A6 for Remediation Criteria for Arsenic in the Yellowknife Area Soils and Sediment.

[a]Chlorophenols include
chlorophenol isomers (ortho, meta, para)
dichlorophenols (2,6- 2,5- 2,4- 3,5- 2,3- 3,4-)
trichlorophenols (2,4,6- 2,3,6- 2,4,5- 2,3,4- 3,4,5-)
tetrachlorophenols (2,3,5,6- 2,3,4,5- 2,3,4,6-)
pentachlorophenol

[b]Nonchlorinated phenolic compounds include
2,4-dimethylphenol
2,4-dinitrophenol
2-methyl 4,6-dinitrophenol
nitrophenol (2-,4-)
phenol
cresol

[c] Aliphatic chlorinated hydrocarbons include
chloroform
dichloroethane (1,1- 1,2-), dichloroethene (1,1- 1,2-)
dichloromethane
1,2-dichloropropane, 1,2-dichloropropene (cis and trans)
1,1,2,2-tetrachloroethane, tetrachloroethene
carbon tetrachloride
trichloroethane (1,1,1- 1,1,2-), trichloroethene

[d] Chlorobenzenes include
all trichlorobenzene isomers
all tetrachlorobenzene isomers
pentachlorobenzene

[e] PCDDs and PCDFs expressed in 2,3,7,8-TCDD equivalents. NATO International Toxicity Equivalency Factors (I- TEFs) for congeners and isomers of PCDDs and PCDFs are as follows:

Congener	TEF
2,3,7,8-T_4 CDD	1.0
1,2,3,7,8-P_5 CDD	0.5
1,2,3,4,7,8-H_6 CDD	0.1
1,2,3,7,8,9-H_6 CDD	0.1
1,2,3,6,7,8-H_6 CDD	0.1
1,2,3,4,6,7,8-H_7 CDD	0.1
O_8 CDD	0.001
2,3,7,8-T_4 CDF	0.1
2,3,4,7,8-P_5 CDF	0.5
1,2,3,7,8-P_5 CDF	0.05
1,2,3,4,7,8-H_6 CDF	0.1
1,2,3,4,7,8,9-H_6 CDF	0.1
1,2,3,6,7,8-H_6 CDF	0.1
2,3,4,6,7,8-H_6 CDF	0.1
1,2,3,4,6,7,8-H_7 CDF	0.1
1,2,3,4,7,8,9-H_7 CDF	0.01
O_8 CDF	0.001

APPENDIX 6

Sampling and Analysis

Intrusive Testing

Testing methods and techniques are expected to be consistent with current day professional standards. Regardless of the method/technique used, all efforts should be made to minimize the spread of contamination as a result of activities during the site assessment.

Field screening of samples, with portable instruments that provide relative results are considered to be acceptable if they are well founded in theory, capable of calibrating measurements to relative or absolute levels of contamination, verifiable in regard to procedures and results and finally, if results of such techniques can be correlated to *Canadian Association of Environmental Analytical Laboratories (CAEAL*) accredited laboratory results.

Test locations should provide an adequately detailed description of the nature, extent and fate of contamination in three dimensions. They should also provide information on potential subsurface contaminant migration pathways. The following should be considered minimum specifications:

- 3-5 boreholes or test pits per potential source area except very small sites where a minimum of 1. Potential source areas include but are not limited to tanks, lines, pump islands, loading areas, drum filling areas, previous underground installations and areas of visible staining. At a typical service station with 1 tank nest, 1 set of lines, 1 pump island, and 1 waste oil tank, this would equate to 4 source test locations.

- Any groundwater contaminant plume(s) associated with the site should be delineated to the minimum acceptable concentration of the contaminant.

- On sites where it cannot be confirmed through historical records that previous tanks and lines have been removed, an appropriate survey (geophysical or otherwise) must be carried out prior to drilling, to determine whether such tanks and lines may be present.

- Sufficient test locations to determine the direction of groundwater flow on-site (minimum of 3 groundwater monitoring wells or piezometers, including at least 1 multilevel installation to assess vertical gradients). Shallow wells are to be screened across the water table to intercept floating product. Bedrock monitoring wells may be required. Construction standards are to follow current day professional standards.

- All soil test locations should extend to the bottom of the contaminated soil zone, to the seasonal low water level, or to bedrock, whichever is shallower.

- All wells will be monitored for the presence of free product.

- Check on-site and off-site manholes and interceptors for hydrocarbons (liquid, vapours).

Sample Analysis

Soil samples may be screened in the field for vapours, staining or odour. All field observations must be included in reports.

Chemical analyses are to be conducted on at least 2 soil samples per well or borehole location (one surface <1.5 m depth, one subsurface >1.5 m depth).

Chemical analyses are to be conducted on at least one groundwater sample from each available well including any on-site water supply wells (Note: sampling may also be required for any nearby, off-site potable water wells).

Chemical analyses for petroleum hydrocarbon impacted sites will include PHC and BTEX (benzene, toluene, ethylbenzene, xylene). Analysis for site-specific parameters may be required, depending on past or present use (e.g., PAHs, lead).

Grain size analyses are to be conducted on at least 1 sample per hydrogeologic unit if the fine-grained soil criteria are to be applied.

Quality Assurance/Quality Control (QA/QC) except for small batches of soil samples (less than 5 samples), at least one blind duplicate should be analyzed per batch of samples submitted for QA/QC purposes. For larger batches (greater than 10 samples), 10% duplicates should be analyzed. The QA/QC results should be presented and interpreted in the report.

For groundwater samples, a blind duplicate and field blank sample should also be collected and analyzed with each batch of samples, regardless of the number of samples tested. Sampling and sample handling protocol must be consistent with accepted practices. In particular, samples for volatile organics must be collected such that there is no headspace in water samples and a minimum headspace in soil samples. Samples should be kept cool until they are delivered to the laboratory. Sample handling procedures should be verified with the receiving laboratory. See *Guidance Manual for Sampling, Analysis and Data Management, Volume 1: Main Report.* CCME, 1993 and *Guidance Manual for Sampling, Analysis and Data Management, Volume 2: Analytical Method Summaries.* CCME, 1993 for further information on sampling and analysis.

Accredited Laboratory

Laboratory analysis of contaminated materials, soil, and water must be conducted by laboratories that have been formally recognized as competent to perform specified tests by *CAEAL*. CAEAL is a non-profit organization dedicated to raising the level of competency, consistency, capability, and communication within environmental testing laboratories in Canada. Their member laboratories voluntarily participate in rigorous programs of proficiency testing and accreditation, demonstrating their commitment to generate high quality data. See Appendix 8 for contact information.

APPENDIX 7

Transportation of Contaminated Soil

The transportation of soils contaminated by flammable liquids is regulated under the *Transportation of Dangerous Goods Regulations* (TDGR). The TDGR require that a completed waste manifest form accompany shipments of hazardous waste. Manifest forms are available from EPS.

The completed manifest form provides:

- Detailed information on the types and amounts of hazardous waste shipped;
- A record of the parties involved in the shipment; and
- Information on the storage, treatment or disposal of the waste and conformation that the waste reached the final destination.

No test is required; as petroleum distillate(s) is a fully specified dangerous good in List II, schedule II of TGDR. The word “waste” must precede the shipping name.

Manifest requirements:

Shipping name:	waste Solids containing flammable liquid, n.o.s.*, (gasoline or diesel, as appropriate)
Classification:	4.1
UN number:	UN3175
Packing group:	II

or

Shipping name:	waste ENVIRONMENTALLY HAZARDOUS SUBSTANCE, SOLID, n.o.s.*, (gasoline or diesel, as appropriate)
Classification:	9
UN number:	UN3077
Packing group:	III

For more information on the requirements of waste management, consult the G*uideline for the General Management of Hazardous Waste (February 1998)*.

The GNWT Department of Transportation can give you more information on the *TDGR.*

APPENDIX 8

Additional Contacts

Canadian Council of Ministers of the Environment (CCME)

CCME works to promote effective intergovernmental cooperation and coordinated approaches to interjurisdictional issues such as air pollution and toxic chemicals. CCME members collectively establish nationally consistent environmental standards, strategies and objectives so as to achieve a high level of environmental quality across the country. Comprehensive literature and technical documentation are available from:

Canadian Council of Ministers of the Environment
123 Main Street, Suite 360
Winnipeg, Manitoba R3C 1A3
Phone: (204) 948-2090; Fax: (204) 948-2125
Website: http://www.ccme.ca; E-mail: info@ccme.ca

Canadian Association for Environmental Analytical Laboratories (CAEAL)

Membership in CAEAL is open to individuals, institutions, user groups, consultants, industrial organizations, regulatory agencies, standard materials and laboratory equipment suppliers, and others interested in the work being carried out in environmental analytical laboratories. More information on CAEAL may be obtained from:

Canadian Association for Environmental Analytical Laboratories
300-265 Carling Avenue
Ottawa, Ontario K1S 2E1
Phone: (613) 233-5300; Fax: (613) 233-5501
Website: http://www.caeal.ca/

Canadian Standards Association (CSA)

The CSA is a not-for-profit membership-based association serving business, industry, government and consumers in Canada and the global marketplace. As a solutions-oriented organization, CSA works to develop standards that address real needs, such as enhancing public safety and health. Advancing the quality of life and helping to preserve the environment. Contact CSA at:

Canadian Standards Association
5060 Spectrum Way
Mississauga, Ontario L4W 5N6
Phone: (416) 747-4000; Fax (416) 747-2473
Website: http://www.csa.ca

PUNCH & BORE CROSSINGS

Fisheries and Oceans Canada
Northwest Territories Operational Statement

Version 3.0

For the purpose of this Operational Statement, the term punch and bore refers to a trenchless crossing method which involves the excavation of a vertical bell hole or shallow depression on either side of the watercourse. Horizontal punching or boring between the two points, at an appropriate depth below the watercourse, completes the creation of a passage-way for the crossing. Punch and bore crossings allow cables and pipelines to be installed under watercourses without imparting any disturbance to the bed and banks. Punch and bore crossings differ from high-pressure directional drilled crossings, in that no pressurized mud systems are required, thereby avoiding the risk of sediment release due to frac-out.

Punch and bore crossings can negatively impact fish and fish habitat due to erosion and sedimentation from site disturbance and dewatering of bell holes or the collapse of the punch or bore hole under the stream. Disturbing riparian vegetation can reduce important shoreline cover, shade and food production areas. Machinery fording the stream can disturb bottom and bank substrates, disrupt sensitive fish life stages, and introduce deleterious substances if equipment is not properly maintained. Impacts can be reduced if an emergency response plan and clean-up materials are in place.

The general order of preference for carrying out a cable or pipeline stream crossing in order to protect fish and fish habitat is: a) a punch or bore crossing, b) high-pressure directional drill crossing (see *High-Pressure Directional Drilling* Operational Statement), c) dry open-cut crossing, and d) isolated open-cut crossing (see *Isolated or Dry Open-cut Stream Crossings* Operational Statement). This order must be balanced with practical considerations at the site.

Fisheries and Oceans Canada (DFO) is responsible for protecting fish and fish habitat across Canada. Under the *Fisheries Act* no one may carry out a work or undertaking that will cause the harmful alteration, disruption or destruction (HADD) of fish habitat unless it has been authorized by DFO. By following the conditions and measures set out below you will be in compliance with subsection 35(1) of the *Fisheries Act*.

The purpose of this Operational Statement is to describe the conditions under which it is applicable to your project and the measures to be incorporated into your project in order to avoid negative impacts to fish habitat. You may proceed with your punch or bore crossing project without a DFO review when you meet the following conditions:

- your planned work is not located in a critical area, as identified in a NWT Community Conservation Plan or other applicable land use plan,
- the crossing is not a wet open-cut crossing,
- the crossing technique will not damage the stream bed or bank and thereby negatively impact fish or fish habitat,
- the site does not occur at a stream location involving known fish spawning habitat, particularly if it is dependent on groundwater upwelling, and
- you incorporate the *Measures to Protect Fish and Fish Habitat when Conducting Punch and Bore Crossings*, listed below.

If you cannot meet all of the conditions listed above and cannot incorporate all of the measures listed below then your project may result in a violation of subsection 35(1) of the *Fisheries Act* and you could be subject to enforcement action. In this case, you should contact the DFO office in your area if you wish to obtain DFO's opinion on the possible options you should consider to avoid contravention of the *Fisheries Act*.

You are required to respect all local, municipal, territorial or federal legislation that applies to the work being carried out in relation to this Operational Statement. The activities undertaken in this Operational Statement must also comply with the *Species at Risk Act* (**www.sararegistry.gc.ca**). If you have questions regarding this Operational Statement, please contact the DFO office in your area (see Northwest Territories DFO office list).

We ask that you notify DFO, preferably 10 working days before starting your work by filling out and sending the Northwest Territories Operational Statement notification form (**www.dfo-mpo.gc.ca/regions/central/habitat/os-eo/prov-terr/index_e.htm**) to the DFO office in your area. This information is requested in order to evaluate the effectiveness of the work carried out in relation to this Operational Statement.

Measures to Protect Fish and Fish Habitat when Conducting Punch and Bore Crossings

1. A punch or bore crossing can be conducted at any time of the year provided there is not a high risk of failure and it does not require in-water activities such as machinery fording.

2. Design the punch or bore path for an appropriate depth below the watercourse to prevent the pipeline or cable from becoming exposed due to natural scouring of the stream bed.

3. While this Operational Statement does not cover the clearing of riparian vegetation, the removal of select plants may be

necessary to access the construction site and to excavate the bell holes. This removal is to be kept to a minimum and within the utility right-of-way.

4. Install effective sediment and erosion control measures before starting work to prevent entry of sediment into the water body. Inspect them regularly during the course of construction and make all necessary repairs if any damage occurs.

5. Machinery fording the watercourse to bring equipment required for construction to the opposite side is limited to a one-time event (over and back) and should occur only if an existing crossing at another location is not available or practical to use. A *Temporary Stream Crossing* Operational Statement is also available.

5.1. If minor rutting is likely to occur, stream bank and bed protection methods (e.g., swamp mats, pads) should be used provided they do not constrict flows or block fish passage.
5.2. Grading of the stream banks for the approaches should not occur.
5.3. If the stream bed and banks are steep and highly erodible (e.g., dominated by organic materials and silts) and erosion and degradation are likely to occur as a result of equipment fording, then a temporary crossing structure or other practice should be used to protect these areas.
5.4. Time the one-time fording to prevent disruption to sensitive fish life stages by adhering to appropriate fisheries timing windows (see the *Northwest Territories In-Water Construction Timing Windows*).
5.5. Fording should occur under low flow conditions and not when flows are elevated due to local rain events or seasonal flooding.

6. Operate machinery on land above the ordinary high water mark (HWM) (see definition below) and in a manner that minimizes disturbance to the banks of the watercourse.

6.1. Machinery is to arrive on-site in a clean condition and is to be maintained free of fluid leaks.
6.2. Wash, refuel and service machinery and store fuel and other materials for the machinery away from the water to prevent any deleterious substance from entering the water.
6.3. Keep an emergency spill kit on site in case of fluid leaks or spills from machinery.

7. Excavate bell holes beyond the HWM, far enough away from any watercourse to allow containment of any sediment or deleterious substances above the HWM.

7.1. When dewatering bell holes, remove suspended solids by diverting water into a vegetated area or settling basin, and prevent sediment and other deleterious substances from entering the watercourse.
7.2. Stabilize any waste materials removed from the work site (including bell holes) to prevent them from entering the watercourse. This could include covering spoil piles with biodegradable mats or tarps or planting them with grass or shrubs.
7.3. After suitably backfilling and packing the bell holes, vegetate any disturbed areas (see Measure 11).

8. Monitor the watercourse to observe signs of malfunction during all phases of the work.

9. For the duration of the work, keep on-site and readily accessible, all material and equipment needed to contain and clean-up releases of sediment-laden water and other deleterious substances.

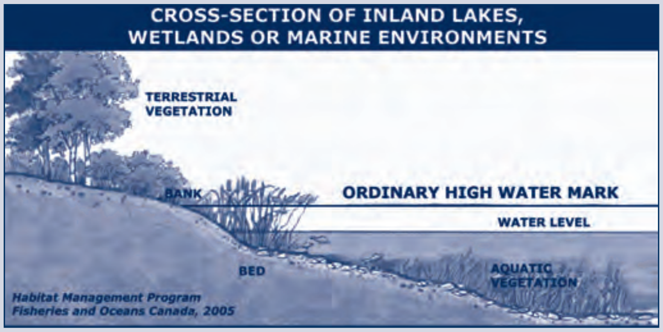
10. Develop a response plan that is to be implemented immediately in the event of a sediment release or spill of a deleterious substance. This plan is to include measures to: a) stop work, contain sediment-laden water and other deleterious substances and prevent their further migration into the watercourse; b) notify all applicable authorities in the area, including the closest DFO office; c) promptly clean-up and appropriately dispose of the sediment-laden water and deleterious substances; and d) ensure clean-up measures are suitably applied so as not to result in further alteration of the bed and/or banks of the watercourse.

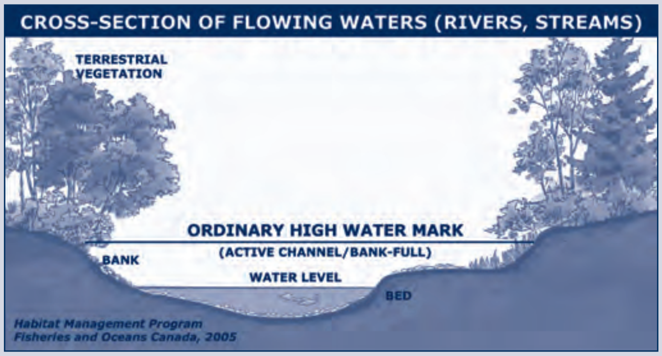
11. Vegetate any disturbed areas by planting and seeding preferably with native trees, shrubs or grasses and cover such areas with mulch to prevent erosion and to help seeds germinate. If there is insufficient time remaining in the growing season, the site should be stabilized (e.g., cover exposed areas with erosion control blankets to keep the soil in place and prevent erosion) and vegetated the following spring. If re-vegetation is not possible due to climatic extremes and/or lack of appropriate seed or stock, the site should be stabilized using effective sediment and erosion control measures. In areas with permafrost, care should be exercised to ensure these measures do not cause thawing or frost heave.

11.1. Maintain effective sediment and erosion control measures until re-vegetation of disturbed areas is achieved or until such areas have been permanently stabilized by other effective sediment and erosion control measures, in the event that re-vegetation is not possible.

Definition:

Ordinary high water mark (HWM) – The usual or average level to which a body of water rises at its highest point and remains for sufficient time so as to change the characteristics of the land. In flowing waters (rivers, streams) this refers to the "active channel/ bank-full level" which is often the 1:2 year flood flow return level. In inland lakes, wetlands or marine environments it refers to those parts of the water body bed and banks that are frequently flooded by water so as to leave a mark on the land and where the natural vegetation changes from predominately aquatic vegetation to terrestrial vegetation (excepting water tolerant species). For reservoirs this refers to normal high operating levels (Full Supply Level).





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Aussi disponible en français

http://www.dfo-mpo.gc.ca/oceans-habitat/habitat/modernizing-moderniser/epmp-pmpe/index_f.asp

DFO/2007-1329

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

GUIDELINE

Planning Horizontal Directional Drilling for Pipeline Construction

September 2004

CAPP Publication 2004-0022

The Canadian Association of Petroleum Producers represents 150 companies that explore for, develop and produce natural gas, natural gas liquids, crude oil, oil sands, and elemental sulphur throughout Canada. CAPP member companies produce approximately 98 per cent of Canada's natural gas and crude oil. CAPP also has 125 associate members who provide a wide range of services that support the upstream crude oil and natural gas industry. Together, these members and associate members are an important part of a $75-billion-a-year national industry that affects the livelihoods of more than half a million Canadians.

Review by June 2009

Disclaimer

This publication was prepared for the Canadian Association of Petroleum Producers (CAPP) by Entec Consulting Limited (Entec), TERA Environmental Consultants (TERA), Canadian Horizontal Drilling Ltd. (CHD) and Geo-Engineering (M.S.T.) Ltd. (Geo-Engineering). Applied Aquatic Research Ltd. (AAR) provided input on water crossings issues and assisted with the review of the document. While it is believed that the information contained herein is reliable under the conditions and subject to the limitations set out, CAPP and Entec, TERA, CHD, Geo-Engineering and AAR do not guarantee its accuracy. The use of this report or any information contained will be at the user's sole risk, regardless of any fault or negligence of Entec, TERA, CHD, Geo-Engineering, AAR, and CAPP or its co-funders.

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OVERVIEW

Horizontal Directionally Drilling (HDD) has proven itself over the last few years to be a very effective technique for the installation of pipelines and other utilities in sensitive or congested areas.

This document provides best practices and recommended procedures for the investigation, planning and execution of an HDD installation for pipeline construction.

It provides guidance on the regulatory, environmental, geotechnical, risk, economics, engineering, contractual and construction considerations that must be evaluated prior to any final decisions to proceed with an HDD installation.

The purpose of this document is to assist pipeline companies, contractors and regulators in planning, evaluating and constructing HDD crossings.

The document has been written to primarily address the installation of oil and gas pipelines in Canada, although concepts and practices contained within are applicable to many industries and jurisdictions.

All pipelines in Canada, including HDD projects, must comply with the requirements of CSA Z662, which is referenced by federal and provincial pipeline regulators. CSA Z662 contains requirements for the design, material selection (including coating selection), construction and operation of pipelines that would apply to HDD projects.

A glossary of technical terms used in this document is provided in Appendix A.

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Acronyms

AENV	Alberta Environment
EUB	Alberta Energy and Utilities Board
ASRD	Alberta Sustainable Resource Development
BHA	bottom hole assembly
CAPP	Canadian Association of Petroleum Producers
CCG	Canadian Coast Guard
CEAA	*Canadian Environmental Assessment Act*
CPWCC	Canadian Pipeline Watercourse Crossing Committee
DFO	Fisheries and Oceans Canada
EM	electromagnetic
ERT	electrical resistivity tomography
GPR	ground penetrating radar
HADD	harmful alteration, disruption or destruction of fish habitat
HDD	horizontal directional drilling
INAC	Indian and Northern Affairs Canada
IOGC	Indian Oil and Gas Canada
I.S.R.M.	International Society for Rock Mechanics
MFO	Minister of Fisheries and Oceans Canada
NEB	National Energy Board
NEB Act	*National Energy Board Act*
NWPA	*Navigable Waters Protection Act*
O.D.	outside diameter
QAES	qualified aquatic environment specialist
SPT	standard penetration tests

1 INTRODUCTION

Horizontal directional drilling (HDD) has emerged as a preferred crossing method in many situations for the installation of oil and gas pipelines as well as other utilities under watercourses, roads, rail lines, steep slopes and other obstacles.

This technology has been enthusiastically embraced by proponents, contractors and regulators as a potentially low impact construction technique. In many cases, however, the suitability of the HDD method must be evaluated and compared to more traditional open-trench construction techniques in order to ensure that an appropriate technique is chosen for the conditions and concerns present at a particular crossing. Recognition of the advantages, limitations and potential risks of HDD is an important step in this evaluation.

The successful design and construction of an HDD is the result of a team effort combining the skills of the regulatory group, owner, engineering consultant, environmental consultant, inspection services and the specialist HDD contractor. Success in this endeavor is measured in more than the successful pull back of the pre-built pipeline drag section. It is the completion of the project for a reasonable cost with minimal environmental impact and in a manner that allows the contractor to make a fair profit. These should be the goals in any type of project including an HDD installation.

It is important to realize that an HDD may represent the critical path on the overall project schedule. In addition, an HDD may have the highest risk of failure of any activities on a project. Therefore, all aspects of planning and design for an HDD need to be assigned a high priority or importance value due to their potential effect on the overall project.

1.1 Purpose of Guidelines

The purpose of this document is to assist pipeline companies, contractors and regulators in the planning, evaluation and construction of HDD crossings. In particular, the document provides guidance for:

- corporate regulatory personnel in determining the necessary course of action during permitting and approval of projects planning an HDD;
- corporate engineering personnel in the planning, contracting and supervision of construction;
- corporate environmental personnel in the planning and provision of support to the construction team;
- contractor personnel in managing expectations of corporate and regulatory personnel; and
- regulatory managers in determining realistic expectations of HDD technology.

1.2 Description of HDD

Horizontal directional drilling is a trenchless construction method utilizing equipment and techniques from horizontal oil well drilling technology and conventional road boring. HDD construction is used to install petroleum pipelines (steel or plastic), fibre optic and electric cables, and water and waste water pipelines where conventional open trench construction is not feasible or will cause adverse disturbances to environmental features, land use or physical obstacles.

HDD technology is used in many situation, including the following:

- lake crossings;
- wetland crossings;
- canal and watercourse crossings;
- valley crossings;
- sensitive wildlife habitat; and
- road and railway crossings.

HDD installation involves four main steps:

1) pre-site planning;
2) drilling a pilot hole;
3) expanding the pilot hole by reaming; and
4) pull back of pre-fabricated pipe.

The following summarizes the main activities that take place during each phase of an HDD. Drilling of the pilot hole and pipe string pull back are illustrated on Figure 1.

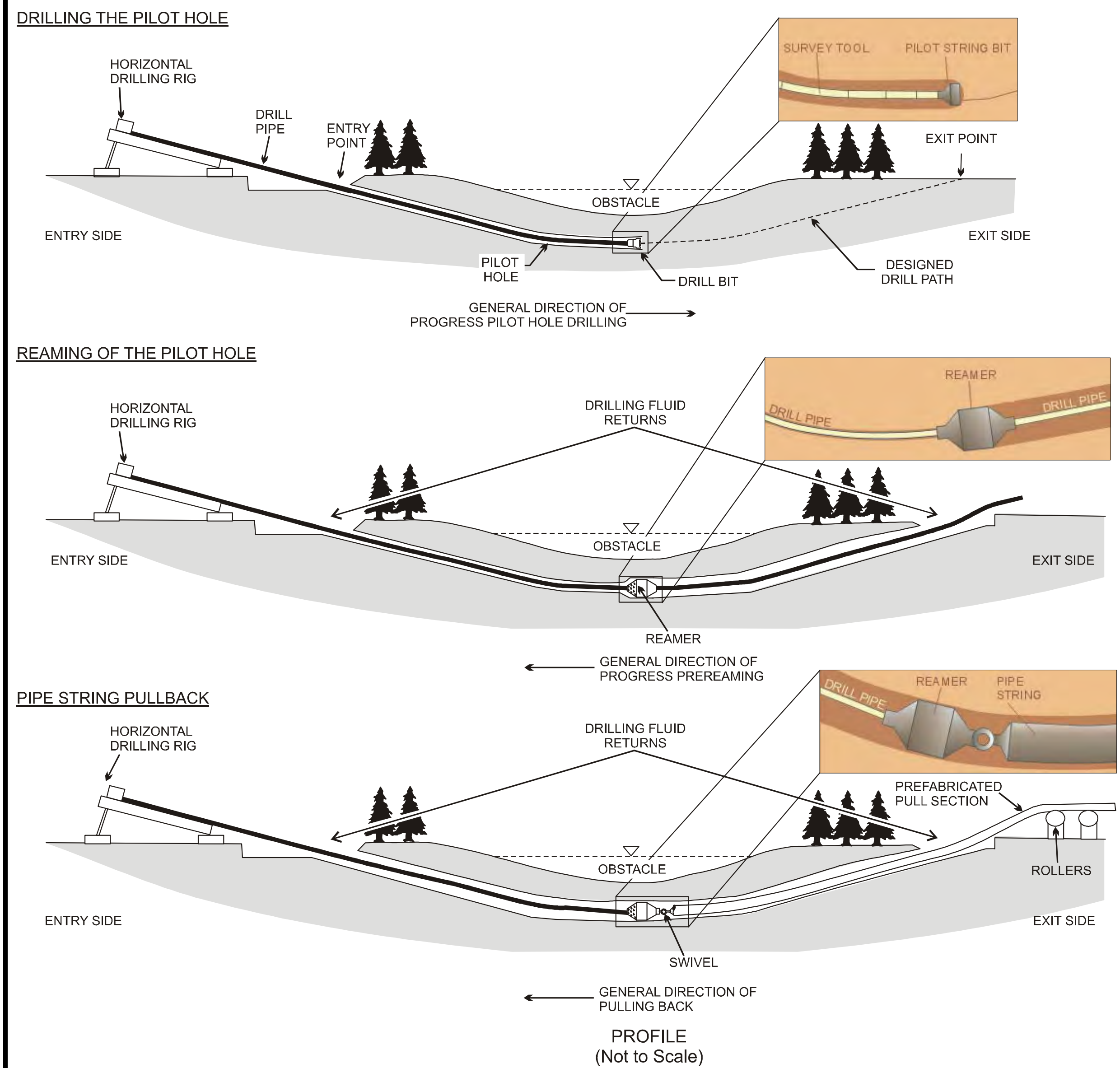
1.2.1 Pre-Site Planning

A determination is made as to whether an HDD is technically and geotechnically feasible by studying existing geological data and conducting field investigations to assess the subsurface conditions and characteristics likely to be encountered during the drill.

If an HDD is determined to be feasible, a drill path is designed to meet the requirements of the crossing and appropriate drill entry and exit locations are selected.

An allowance is made in the design of the drill path for any potential changes in the obstacle (i.e., stream migration or cutoff development) to be drilled under and the drill entry and exit points are refined.

Figure 1 Watercourse Crossing – Horizontal Directional Drill



CAPP Canadian Association of Petroleum Producers	PLANNING HORIZONTAL DIRECTIONAL DRILLING FOR PIPELINE CONSTRUCTION	
	WATERCOURSE CROSSING – HORIZONTAL DIRECTIONAL DRILL	
	1. September 2004	2. FIGURE. NO. 1

1.2.2 Drilling the Pilot Hole

An HDD drill rig and supporting equipment are set-up at the drill entry location determined during the pre-site planning phase.

A pilot hole is drilled along the predetermined drill path.

Periodic readings from a probe situated close to the drill bit are used to determine the horizontal and vertical coordinates along the pilot hole in relation to the initial entry point; the pilot hole path may also be tracked using a surface monitoring system that determines the down hole probe location by taking measurements from a surface point.

Drilling fluid is injected under pressure ahead of the drill bit to provide hydraulic power to the down hole mud motor (if used), transport drill cuttings to the surface, clean build-up on the drill bit, cool the drill bit, reduce the friction between the drill and bore wall, and stabilize the bore hole.

1.2.3 Reaming of the Pilot Hole

The down hole assembly is removed from the drill string upon breaking the ground surface at the exit location and is replaced with a back reamer;

The drill string is pulled back through the bore hole and the back reamer enlarges the diameter of the drill hole;

The reamer may be pulled from the pipe side of the HDD crossing if additional passes with the reamer are required to achieve the desired bore hole diameter; and

The reaming stage may not be necessary during HDDs for small diameter pipelines where the bore hole created by the pilot hole drill is of adequate size to pull back the pipe string (refer to Section 8.5.1).

1.2.4 Pipe String Pull back

Pipe is welded into a pipe string or drag section, that is slightly longer than the length of the drill, on the exit side of the bore hole.

The pipe is typically coated with a corrosion and abrasion resistant covering, and is commonly hydrostatically pretested to ensure pipeline integrity.

The pipe string is pulled over rollers into the exit hole and the pull back continues until the entire pipe string has been pulled into the bore hole.

The external coating of the pipe string visible at the entry point is inspected for damage upon completion of the pull back.

An internal inspection of the pipe string is performed to identify any damage done to the pipeline during the pull back.

Upon successful pull back of the pipe string, the drilling equipment is dismantled and demobilized.

The pipe string is connected to the conventionally laid pipeline and work areas are reclaimed with the rest of the pipeline right-of-way.

1.3 Workspace Requirements

Workspace for an HDD may require clearing and grading, depending on the entry and exit sites selected for the drill. Since the drill entry location or entry side accommodates the drill rig and supporting equipment, the entry side location requires satisfactory access as well as stable ground conditions to support heavy equipment (Figure 2). Equipment typically found on the entry side of a HDD include:

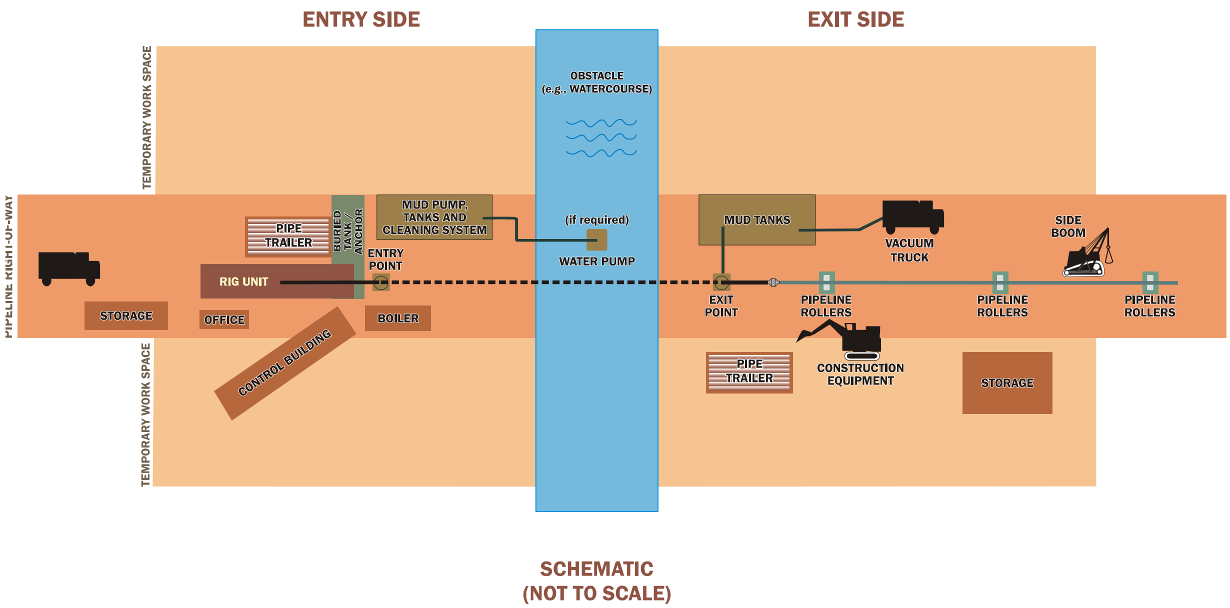
- the rig unit;
- power unit and generators;
- drill pipe rack and drill pipe;
- water pump;
- drill mud supply;
- drill mud mixing tank;
- drill mud pump; and
- mud handling and cleaning system.

Since the drill exit side is the location for the fabrication of the pipe string as well as where the pipe string is inserted into the bore hole, the workspace required is typically longer to accommodate the pipe string (Figure 2) and may require extra temporary workspace outside of the right-of-way known as "false right-of-way". Equipment typically found on the exit or pipe side of the HDD includes:

- exit mud containment tanks/pits;
- cuttings settlement tanks/pits;
- pipe racks and product pipe;
- rollers and pipeline handling equipment;
- side booms and other heavy equipment; and
- pipelines, welding, coating and testing equipment.

Selection of the drill site and exit location is addressed in Section 3.4.2

Figure 2 Horizontal Directional Drill Set-up



CAPP Canadian Association of Petroleum Producers	PLANNING HORIZONTAL DIRECTIONAL DRILLING FOR PIPELINE CONSTRUCTION	
	HORIZONTAL DIRECTIONAL DRILL SET-UP	
	1. September 2004	2. FIGURE. NO. 2

2 REGULATORY AND INFORMATION REQUIREMENTS

The regulatory requirements for undertaking an HDD in Canada depend upon the jurisdiction in which a project is to be built. Each watercourse crossing may be subject to federal, provincial, territorial and local regulatory review. Many jurisdictional agencies have codes of practice, guidelines and/or policies regarding watercourse crossings, and require notifications and/or applications for permits, authorizations or licenses.

The following sections describe the federal, provincial and territorial regulatory framework. Information requirements for each of these agencies are briefly discussed. This document has been written to reflect the regulatory information requirements at the time of publication. It does not address draft or proposed acts, codes of practice, guidelines or policies.

Appendix B provides a brief, summary checklist of the regulatory framework and the appropriate contacts. Since the regulatory requirements are complex and continually changing across the country, the responsibility to ensure that all requirements are met falls upon the proponent. Project planners should confirm with the appropriate agencies that the applicable permit applications are made and regulatory requirements have been identified.

2.1 Federal Jurisdictions

There are two federal acts which are most applicable to HDD watercourse crossings in Canada: the *Fisheries Act* and the *Navigable Waters Protection Act* (*NWPA*). Other acts are applicable but should only be considered in certain situations.

2.1.1 Fisheries Act

The *Fisheries Act* was enacted to protect fish, fish habitat and water frequented by fish, and to provide for sustainable fisheries in Canada.

There are several sections in the *Fisheries Act* (paraphrased below) which are most likely to pertain to HDD pipeline watercourse crossings:

Section 20	Provides for safe passage of fish.
Section 22	Provides for flow of water and passage of fish.
Section 30	Provides for water diversions or intakes to have a fish guard or screen.
Section 32	Prohibits the destruction of fish by any means other than fishing except as authorized by the Minister of Fisheries and Oceans (MFO) or regulation.

Subsection 35(1)	Prohibits works or undertakings that result in harmful alteration, disruption or destruction of fish habitat (HADD).
Subsection 35(2)	Allows for the authorization of HADD by the MFO.
Subsection 36(3)	Prohibits the deposition of deleterious substances in waters frequented by fish.

2.1.2 Navigable Waters Protection Act

The *NWPA* provides a legislative mechanism for the protection of the public right of marine navigation on all navigable waterways of Canada. This is accomplished through authorization of the construction of works built or placed in, over, through or across navigable waterways.

A navigable waterway is defined as being any body of water capable of being navigated by floating vessels of any description for the purpose of transportation, commerce or recreation. This includes both inland and coastal waters. The authority to determine the navigability of a waterway rests with the MFO or his/her designated representative.

The pertinent sections of the *NWPA* (paraphrased below) for HDD pipeline watercourse crossings are found in:

Section 5(1)(a)	No work shall be built or placed in, on, over, under, through or across any navigable water unless approved by the Minister.
Subsection 5(2)	Except in the case of a bridge, boom, dam or causeway, paragraph 5(1) (a) does not apply to any work that in the opinion of the Minister does not interfere substantially with navigation.

All pipelines that cross a navigable water are subject to review under the *NWPA*. In recognition of the low risk of some crossings, the Central, Arctic and Pacific regions have issued guidelines relaxing the need for application as long as certain conditions are followed. If the following conditions (paraphrased) are met, an HDD may be undertaken in these regions without applying for *NWPA* approval:

- no tools, equipment, vehicles or temporary structures are to remain in the water after completion of the work;
- any debris or other material accumulated as a result of the HDD must be removed;
- warning signs must be placed up- and downstream of construction;
- navigation must be maintained at all times;
- navigation stakeholders must be consulted in advance;

- the bed, if disturbed, must be restored to natural contours; and
- disturbed shorelines must be stabilized.

A thorough review of the guidelines (*e.g.,* Fisheries and Oceans Canada (DFO), 2003, 2004), should be made in advance on deciding to not apply for review by the Canadian Coast Guard (CCG).

In several situations these guidelines do not apply and an approval under the *NWPA* is required. These include:

- all National Energy Board (NEB) regulated pipelines;
- all crossings of waterways charted by the Canadian Hydrographic Service;
- all construction requiring a temporary bridge; and
- all crossings of a specified watercourse (21 major watercourses in the Central and Arctic regions are listed).

Where review and approval is required from CCG, applications should include a letter of application, site and construction drawings, authorization by owner, and environmental assessment documentation.

2.1.3 Other Federal Legislation

HDD watercourse crossings which are part of an international or interprovincial pipeline are subject to review under the *National Energy Board Act* (*NEB Act*) and are also subject to approval by CCG, under Section 108 of that Act and the *NWPA*.

The *Canadian Environmental Assessment Act* (*CEAA*) may also be triggered if:

- a federal authority is the proponent of a project;
- a project is being financed in whole or part by a federal authority;
- a project is being conducted on federal lands; or
- a federal authority is issuing a permit, license or approval for a project.

In the event that *CEAA* is triggered on a segment of the route (*e.g.,* the project is being undertaken on an Indian Reserve or an authorization under the *Fisheries Act* is required (*e.g.,* S. 35(2)), the Responsible Authority (*e.g.,* DFO) will establish the scope of the project and the scope of the assessment, and undertake the appropriate review process under *CEAA*.

First Nations self-government, land claims and protocols are an ever-changing consideration in the approval process. Documenting these requirements and recommendations is beyond the scope of this document. Nevertheless, to facilitate a timely review and approval, it is important that all proponents and regulators become familiar with the relevant agreements and other requirements. The incorporation of appropriate First Nations in the consultation and construction planning process will further assist in the acquisition of approvals.

Further details on these other regulatory conditions are summarized in Watercourse Crossings (Canadian Pipeline Watercourse Crossing Committee (CPWCC) 1999).

2.2 Provincial and Territorial Jurisdictions

Each provincial and territorial jurisdiction has various legislation, regulations, codes of practice, policies and guidelines affecting pipeline watercourse crossings. Most provinces and territories require a permit, license and/or other authorization to use/affect surface water and/or make alterations to streambeds and banks.

The review of applications to alter streambeds and banks generally involves the appropriate provincial fisheries management agencies and may include DFO depending on the agreement the province or territory has with DFO. The issuance of a permit, license or approval generally does not exempt the applicant from the provisions of any other applicable provincial or federal legislation, or any other processes of law including local or municipal by-laws.

The bed and banks of a watercourse are, in most instances, considered public lands in all provinces and territories in Canada. Proponents must apply to the appropriate provincial or territorial agency for approval to cross these lands.

An overview of the regulatory requirements for each province and territory is beyond the scope of this document, although Appendix B outlines the permits potentially required in each jurisdiction in Canada.

2.3 Other Guidance

With the emergence of HDD as a common construction technique, several guidance documents have been produced which may by useful in planning an HDD. These include but are not limited to:

- Directional Crossing Contractors Association. Guidelines for a Successful Directional Crossing Bid Package. 1995.
- Watercourse Crossings, Second Edition. Canadian Pipeline Water Crossing Committee. November, 1999.
- Horizontal Directional Drilling Best Management Practices Manual, Topical Report. Gas Research Institute. May, 2002.
- Horizontal Directional Drilling Practices Guidelines. HDD Consortium. 2004
- Alberta Energy and Utilities Board (EUB) Guide 50; Drilling Waste Management, Interim Directive ID 99-05

3 SELECTION OF HDD AS THE PREFERRED CROSSING METHOD

The decision to install an HDD crossing at a specific location is the result of a process that addresses the following:

- overall pipeline route selection;
- crossing location selection;
- crossing method selection;
- other selection criteria such as:
  - availability of access,
  - need for and suitability of vehicle crossings,
  - siting of entry and exit points,
  - dimensions of the No Drill Zone, and
  - availability of a water source.

3.1 Pipeline Route Section

The selection of a preferred water crossing location based on an overland pipeline routing assessment should also consider the method of crossing, alignment, and access for the HDD construction. The pipeline routing should allow for layout areas, entry/exit pads, access routes, and minimal points of inflection in the design drill path and the pipe string layout area.

3.2 Crossing Location Selection

The selection of the crossing should be undertaken in conjunction with the route selection to allow the following:

- flexibility in using various crossing methods, especially if the HDD fails and an alternative crossing technique is required;
- flexibility to use various accesses or vehicle crossing methods; and
- flexibility in refining the exact crossing location in the event that constraints prevent certain alignments.

3.3 Crossing Method Selection

In selecting a pipeline watercourse crossing method, many factors must be taken into consideration. These include, among others:

- pipeline diameter;
- project schedule (*i.e.*, desired schedule for the pipeline to be operational);
- watercourse crossing width, depth and flow;
- environmental sensitivity and associated constraints;
- geotechnical concerns;
- substrate composition;
- hydrological data;
- costs of the various alternatives;
- navigation;

- amount of working space;
- regulatory requirements and conditions including timing constraints;
- equipment availability;
- contractor expertise;
- downstream water users;
- landowner and community issues;
- engineering constraints; and
- construction season.

(CPWCC 1999)

The selection of a crossing method is an exercise in striking a balance among the considerations listed above to derive the most practical solution. The method that is preferred is usually that which is geotechnically feasible and offers the required level of environmental protection for the lowest cost. Selection of an HDD crossing when other methods are more cost effective, technically feasible and offer sufficient environmental protection may be inappropriate. If an HDD is the strongly preferred method by regulators and this method is considered to have a low likelihood of success or is otherwise impractical, the regulators should be provided detailed information on the crossing method selection process and the rationale for the rejection of the HDD method. Additional information on the crossing method selection process is available in CPWCC (1999).

3.4 Other Selection Issues

Assuming that HDD has been selected as the preferred crossing method, the following other selection issues must be evaluated.

3.4.1 Access

Pipeline routing and drilling execution planning should consider that access to both sides of the drill will be required during the HDD construction process.

If adequate access to the crossing cannot be provided on both sides of the watercourse and the watercourse is suitable for the installation of a crossing structure, a temporary crossing structure may need to be installed for vehicle and equipment traffic. As with the selection of the crossing method, selection of the vehicle crossing technique also involves striking a balance between many of the same considerations listed above for crossing method selection to derive the most practical solution. The technique that is preferred is usually one which offers the required level of environmental protection for the lowest cost.

Access will also be required:

- to a water source during the installation of the HDD (see Section 3.4.4);
- for monitoring of the drill path; and
- during clean-up operations in the event of a drilling fluid release to surface.

Sediment and erosion control protection plans may be warranted to ensure that access creation or use do not result in adverse effects.

3.4.2 Drill Entry and Exit Site Selection

The selection of the drill and exit locations will need to consider the following:

- the terrain must be cleared, leveled and suitable for the work (sites with negligible longitudinal or side slopes are preferred);
- entry and exit location should be of sufficient size and configuration to undertake the work safely[1]; this should include consideration of:
  - drill rig entry and exit points (note that generally the entry point should ideally be at an equal or lower elevation than the exit point);
  - rig size and layout requirements;
  - pipe laydown area or false right-of-way (note that a straight approach to the exit point is preferred to avoid the need for false right-of-way);
  - fabrication area;
  - returns pit; and
  - bulk storage of materials;
- the resulting drill path must be feasible with a low risk of inadvertent returns; and
- existing infrastructure and land use.

3.4.3 No Drill Zone

A No Drill Zone can be identified that addresses geotechnical issues and concerns at the proposed crossing site. As defined by the geotechnical engineer, the No Drill Zone is the upper limit of potential drill paths between specified entry and exit locations, intended to ensure that the bore is maintained within geological materials suitable for an HDD while providing sufficient cover to mitigate potential inadvertent return concerns.

As detailed in Section 6.3, definition of the No Drill Zone for a proposed HDD crossing is influenced by a number of factors, including:

- crossing area terrain conditions, in terms of the difference in elevation between entry and exit locations and along the HDD alignment, that determine, in large part, the minimum recommended depth of cover;
- subsurface soil and bedrock stratigraphic conditions, and the suitability of the various units for directional drilling;
- river engineering considerations, including depth of scour during the design flood event and potential for bank/meander migration and cut off development; and

[1] In general, for small HDD applications, entry site should be approximately 40 m x 40 m, exit site approximately 30 m x 20 m. For larger HDD applications, entry site should be approximately 60 m x 60 m, exit site should be approximately 40 m x 30 m, excluding false right-of-way, if required. The contractor should be requested to provide his specific requirements prior to construction.

- the presence of active, inactive and potential landslide features, and other geotechnical "problem" areas, which should be avoided by the design drill path.

All potential drill paths should be designed to pass outside of the No Drill Zone.

While the No Drill Zone is typically defined in terms of geotechnical considerations, it may also be influenced by environmental and socio-economic concerns, such as wildlife concerns, rare plant occurrences, social resources (*e.g.*, land use) and cultural resources (*e.g.*, archaeological sites), etc. Specific studies may be necessary to identify the presence of these environmental and cultural features. Relocation of the entry and/or exit point, thereby altering the length of the design drill path, may provide a means of mitigating some of these non-geotechnical concerns.

3.4.4 Water Source

The availability of a water supply to the HDD site should also be considered during the planning stage of the project. Water will be required for the following:

- initial drilling fluid make-up;
- additional drilling fluid as the drill progresses;
- replacement fluid for drilling fluid escaping into the formation due to seepage or hydraulic fracture; and
- pretesting, where warranted, of the pipe string.

Hydraulic fractures can greatly increase the water requirements during an HDD project.

Water can be pumped from a water body to the drill site or hauled to storage tanks onsite. Factors to be considered in selecting a water supply are:

- access to the water body;
- flow restrictions;
- regulator approval;
- construction schedule (*i.e.*, air temperature, anticipated streamflow/volume and water quality); and
- physical limitations such as the distance and/or elevation of the entry point from the water body.

4 RISK CONSIDERATIONS

As with all construction techniques, a degree of risk and unpredictability is associated with the use of HDD applications. It is recommended that a project team be assembled early in the planning and design process in order to identify and assess potential risk, as well as develop plans to minimize the risks. Although HDD projects vary widely in complexity, most encounter site-specific characteristics that differ from previous projects. The project team may be composed of the proponent; engineering, geotechnical and environmental consultants; the HDD contractor and the pipeline contractor. Close consultation with regulators and land authorities can assist in the acquisition of initial approvals as well as ensure that alternate plans can be readily implemented if insurmountable problems arise.

Risk can generally be divided into three types: regulatory risks; construction risks; and operations risks.

4.1 Regulatory Risk

Regulatory risk can be encountered during:

- the application and approvals stage of a project; and
- construction.

During the application and approvals stage, the project may be delayed or rejected if insufficient information is submitted for regulator review. In the event that an application is approved, insufficient information may cause the regulatory agency to invoke restrictive conditions to ensure protection of the environmental resources.

During construction, an inadvertent release of drilling fluid to the environment or other contravention of an act may result in possible charges being laid by the regulatory agencies. These infractions could include:

- Section 32 of the *Fisheries Act* - unauthorized killing of fish
- Section 35 of the *Fisheries Act* - unauthorized HADD
- Section 36 of the *Fisheries Act* - unauthorized release of deleterious substances

In a regulatory climate in which more emphasis is being placed on self-regulation, industry can expect that any violation of the regulatory requirements may result in more rigid interpretation of the legislation. Therefore, it is imperative that all permits/approvals are obtained and applicable conditions are implemented to demonstrate that industry can be trusted to self-regulate.

4.2 Construction Risk

Success of an HDD installation is dependent upon the ability of the project team to minimize the causes of failure. The risks associated with each crossing will vary according to many factors. These include but are not limited to:

- inadequate planning;
- lack of contingency planning;
- inexperienced field personnel;
- overestimation by the contractor in the firm's abilities;
- insufficient quantity and size of equipment onsite; and
- inadequate knowledge of subsurface conditions.

(CPWCC 1999)

Construction risk on a project can be minimized by ensuring that sufficient planning is conducted and an adequate geotechnical investigation is carried out. Another means of addressing risk on a project is through the type of contract that is used (see Section 9.1).

Table 1 summarizes some of the more common problems associated with HDD and identifies the construction risks associated with each.

Table 1 - Construction Risks Associated with an HDD

Potential HDD Difficulty	Construction Risk
Loss of drilling fluid	Variable depending on volume and connectivity to surface or water body.
Loss of circulation	Complete loss of circulation indicates a loss of drilling fluid (see above).
Drilling mud seepage directly into watercourse	Sediment load and deposition with possible adverse effects on fish, fish habitat, hydrology and downstream water users.
Drilling mud seepage onto land and then into watercourse	Sediment load and deposition with possible adverse effects on fish, fish habitat, hydrology and downstream water users. Additional adverse effects on wildlife, vegetation, soils, heritage resources and current land use may occur on land.
Collapsed hole	Loss of topsoil and unexpected widening of the area of disturbance. Extended duration of disturbance is likely.
Washout of cavities and collapse of right-of-way	Loss of topsoil and unexpected widening of the area of disturbance.

Potential HDD Difficulty	Construction Risk
Stuck drill stem	An unexpected widening of the area of disturbance if a wide and deep excavation is necessary to retrieve the equipment. Extended duration of disturbance is likely.
Lost tools	Extended duration of disturbance and potential for a redrill.
Damaged pipe or coating	Extended duration of disturbance and potential for a redrill.

4.3 Operations Risk

The risks associated with an HDD installation during operations are generally considerable less that those of a traditional trenched crossing. In particular, the risk of the following problems is minimized or eliminated:

- maintenance of disturbed banks or stream bed;
- exposure of pipe during peak flow events or due to ice scour; and
- damage of pipe due to anchors or other third party activities.

Increased risks include:

- pipe is inaccessible for repairs due to depth of cover;
- corrosion due to undetected damage to pipe coating;
- subsidence at entry and exit points; and
- visual leak detection is not possible.

5 ECONOMIC CONSIDERATIONS

5.1 Potential Economic Advantages of HDD

The development of guidance systems specifically for HDD use has made HDD technology increasingly efficient and productive. Experience acquired by HDD contractors and operators during the early period of HDD use has resulted in more competent operating directional equipment as well as more knowledgeable contractors. There are several potential economic advantages of employing HDD construction techniques as opposed to conventional pipeline installation techniques including:

- increased use of HDD technology has resulted in associated equipment and labour costs being spread over multiple projects, making individual projects more affordable;
- high installation performance;
- no additional expense arising from closed streets, irrigation canals or railways;
- minimal to non-existent reclamation costs to the obstacle crossed since surface disruption along the alignment drilled is minimized (inadvertent drilling mud release still requires mitigation);
- the need for removal, restoration, monitoring, maintenance and other long-term costs associated with trench settlement is eliminated through the use of HDD crossings;
- road cuts, which are expensive to restore, are minimized;
- HDDs are possible year-round (instream timing restrictions may apply to conventional construction methods); and
- HDD can be faster than conventional crossing methods.

5.2 Costs of HDD Applications

The costs associated with an HDD are influenced by:

- location;
- access;
- environmental setting;
- geological characteristics;
- obstacle to be crossed;
- required rig size to complete the drill;
- total length of the drill; and
- pipe diameter(s) to be installed.

The types of costs associated with HDDs, as with any construction activity, are direct costs, indirect costs and potential risks to the public. Operating and maintenance costs of completed projects should also be considered for HDD projects.

5.3 Direct Costs and Benefits of HDD Applications

Direct costs are readily identified within the scope of a project and are paid for directly from the budget of a project (*i.e.*, the cost of the project itself). Considerable direct costs are often associated with conventional pipeline construction installation methods. Common costs related to conventional construction methods include:

- excavating equipment required for trenching;
- labour;
- topsoil and spoil handling;
- backfill costs; and
- reclamation and restoration costs.

Where conventional construction impacts traffic volumes, water bodies or environmentally sensitive areas, direct costs are often substantially increased. HDD technology can be used to avoid environmentally sensitive areas, areas of large traffic volumes and water bodies, and minimizes the requirements for moving and handling large quantities of topsoil, spoil and backfill. Consequently, there are often some cost saving advantages over conventional installation techniques. In addition, the costs of using trenchless technology do not increase with depth of cover as dramatically as with conventional construction methods, thereby reducing overall costs.

5.4 Indirect Costs and Benefits of HDD Applications

Indirect costs are tangible and intangible costs which cannot be included in the project costs. Indirect costs accumulated by the proponent on a project depend upon the work site and the issues present or encountered. Factors affecting indirect costs include:

- traffic obstruction;
- road damage;
- environmental damage;
- air and noise pollution;
- project delays; and
- social costs.

With the potential to reduce the approval period and construction duration, and avoid or reduce overall disturbance, HDD applications appeal to indirect cost reduction by minimizing interference with community activities and operations, and adverse environmental effects. Air and noise pollution may also be minimized due to the often reduced installation time. Traffic obstruction and road damage are avoided, since the roads are not affected on the surface by construction. Safety issues and costs associated with HDD applications may also be less than those related to conventional construction techniques (*i.e.*, open excavation), and fewer people are required onsite for HDDs, reducing the chance of injury in the workplace.

6 GEOTECHNICAL CONSIDERATIONS

The design drill path must be developed taking into account the geological setting for the project and geotechnical and hydrogeological issues at the crossing site.

6.1 Geotechnical and Hydrogeological Issues

From a geotechnical perspective, a number of issues should be taken into account during the HDD feasibility investigation as well as during design and construction of the directional drill, including:

- the distribution and characteristics of the surficial overburden deposits;
- the presence of high plastic clay and bentonitic shale bedrock materials; and
- the occurrence of structurally complex, hard and/or abrasive bedrock formations.

These issues are briefly addressed below.

6.1.1 Surficial Overburden Deposits

In general, cohesive soils, such as clays, silty clays and silty-clayey tills, are self-supporting and an open bore should be achievable. An open bore can often also be maintained through “dirty” sands and clayey silts, and even cohesionless clean silt and sand materials (provided the bore is full of drilling mud). However, medium to coarse-textured granular materials (*e.g.*, gravels, cobbles and boulders) can give rise to a number of problems during HDD construction, including:

- bore instability or collapse during drilling of the pilot hole and subsequent reaming passes, that may result in the drill string becoming stuck;
- loss of drilling fluids to the formation; and
- release of drilling fluids to the environment.

Mitigative measures may include:

- maintaining drilling mud in the bore hole at all times by locating the entry and exit points above cohesionless silt-sand zones;
- evaluating alternative drill paths that avoid or minimize exposure to the problematic soil materials;
- casing or excavating through near surface silt, sand or coarse-textured deposits; and
- using drilling additives to consolidate and reduce the permeability of these materials.

Strict monitoring of fluid volumes, annular pressure and cutting returns will assist in ensuring that bore hole plugging and fluid losses are detected and addressed.

6.1.2 Clays and Shales

Clays and soft shale formations of low to medium plasticity (based on Atterberg Limits), have a low potential to swell and typically can be readily penetrated during directional drilling. Conversely, high plastic clays and bentonitic shales have a potential to swell and, during drilling of the pilot hole, reaming or pull back of the pipe string, the bore may be partially or completely sealed. Hydraulic fracturing of the formation and migration of fluids out of the bore can result. Mitigative approaches may include:

- avoiding high plastic clays and bentonitic shale formations, if feasible;
- designing the drill path such that exposure to these problematic materials is minimized;
- using safe drilling practices to ensure the bore hole is sized and cleaned properly; and
- adopting an annular pressure program to ensure the bore hole is being properly monitored throughout the drilling process.

High plasticity materials may also impact the viscosity of the drilling fluids. A drilling execution plan should be developed that includes a properly engineered fluids program addressing swelling clays and the removal of cuttings from the drilling fluid.

6.1.3 Bedrock Formations

From a geotechnical perspective, competent bedrock is one of the preferred materials for directional drilling. In most cases, good bore hole stability allows an open bore to be maintained during all stages of the drilling process. Nevertheless, problems can arise due to the presence of:

- structural complexity, in terms of folded and faulted bedrock strata, along the drill path;
- rock mass discontinuities related to tectonic processes (*e.g.*, joints and fractures)
- complex subsurface stratigraphic conditions, giving rise to rapid changes in lithology and bedrock properties;
- coal seams; and
- large voids related to solution processes (*e.g.*, karst openings in carbonate formations).

Where the bedrock structure is complicated by folding and faulting, the drill path will intersect discontinuities in the rock mass, such as bedding and joints, at a variety of angles. The drill bit may be deflected in competent lithologies, when the pilot hole intersects such discontinuities at low angles, and steering problems can result.

Jointing and fracturing can give rise to fluid migration during drilling and be a source of bore hole instability problems. Fluid losses can be a major concern if the bedrock is highly jointed/fractured. One mitigative approach is to consider using drilling additives to consolidate and reduce the permeability of joints and fractures.

Complex subsurface stratigraphic conditions can give rise, in turn, to rapidly changing variations in bedrock properties, potentially resulting in directional control and steering problems. Hard (high compressive strength) and/or highly abrasive bedrock will also affect schedule and costs and, in some instances, the feasibility of the HDD project could be put in question. Mitigative approaches may include avoiding high compressive strength bedrock units in the design of the drill path and/or minimizing the length of drill path that encounters these formations. Application of air hammering or air drilling techniques could also be considered if drilling through these materials is unavoidable.

All coal seams encountered during the geotechnical investigation should be identified on the bore hole logs. In many cases, they are extensively jointed/fractured and, as such, can be a source of loss of circulation and/or mud control problems. During directional drilling, coal particles can also clog pumps and create problems with cutting returns.

Depending on their extent, voids related to bedrock solution processes can also be a source of loss of circulation and mud control problems. Karst openings in limestone and dolomite formations are most commonly encountered but solution cavities can also occur in gypsum and salt- and potash-bearing bedrock formations.

6.1.4 Hydrogeology

The main hydrogeological issue relates to the presence of artesian conditions. These are typically encountered where impermeable clay or shale bedrock layers overlie permeable water-bearing sands-gravels or sandstone bedrock at depth, forming a confined aquifer. When intersected by the pilot hole, such aquifers may be large-volume sources of groundwater under pressure. As such, mud quality and fluid management problems may result. Mitigative approaches include casing or cementing off the confined aquifer zone.

Cross-contamination of aquifers may also be a concern, particularly when the directional drill path is very deep.

6.2 Geotechnical Investigation

The geotechnical investigation is a critical part of the information gathering and risk assessment phases of planning an HDD. The scope of work should include: review of background information, a field reconnaissance, completion of a program of field drilling and sampling, geophysical surveys if appropriate, laboratory testing, and office analysis. It should be recognized that subsurface conditions are generally not homogeneous and, for this reason, may be difficult to fully investigate.

Results of the investigation should be presented in a geotechnical report (Section 6.3). The report can be referenced in final design and should be suitable to be provided to prospective HDD contractors to assist them in preparing bids to construct the crossing.

6.2.1 Information Review

The first stage of the study should involve a review of background geological and geotechnical information. Data sources may include: published surficial and bedrock geology maps and reports prepared by federal, provincial and territorial government agencies, stereo air photo coverage of the crossing area, and maps and surveys prepared for the project by the proponent. If available, unpublished information on previous pipeline-related and/or HDD projects in the same general area should also be referenced.

6.2.2 Field Reconnaissance

The reconnaissance should be carried out in advance of the drilling and sampling program. The objectives should be to review and document site conditions pertinent to construction of the proposed HDD crossing as well as to review access and logistics for the drilling and sampling program.

Crossing area characteristics of interest include:

- the presence of surface or subsurface facilities, if any, in particular pipelines and other buried utilities (these must be precisely located prior to initiating the field drilling program);
- existing natural and man-made exposures of surficial overburden and bedrock materials, which should be logged and documented;
- if relevant, hydrological and river engineering characteristics of the water body being crossed; and
- active, inactive and potential landslide features and their distribution relative to the proposed HDD alignment.

During the access and field logistics review, access conditions for drilling equipment should be assessed. If ground access is available, a truck mounted or track mounted drilling rig can be utilized during the drilling/sampling program. Otherwise, a helicopter-supported investigation may need to be considered.

6.2.3 Field Drilling and Sampling Program

Logging and sampling of bore holes provides the best means of obtaining information on and gathering representative samples of the subsurface soils and/or bedrock to be encountered along the drill path. On this basis, it should be possible to develop a subsurface geological model to assist in identifying the distribution of overburden and bedrock materials to be expected along the proposed HDD alignment.

Anticipated ground and site access conditions will determine the type of drill rig to be employed. Typically, bore holes are completed using a truck-mounted or track-mounted rig capable of drilling the soil and bedrock materials expected at the site. As noted, where ground access into the proposed bore hole locations is not available, helicopter-transportable drilling equipment may have to be used. For some bedrock investigations, diamond coring equipment can be utilized. The scope of the drilling program, in terms of number of bore holes and depths, will depend on the length of the HDD, projected length of the design drill path and the anticipated complexity of subsurface conditions. The bore hole locations should be chosen to minimize the risk of interception by the HDD and subsequent inadvertent returns following the bore hole to the surface.

The soil and bedrock strata being penetrated are logged from cuttings returned to the surface during drilling, samples from standard penetration tests (SPT), spoon and Shelby tubes, as available, and observations of drill performance. If soil conditions are suitable, cone penetration tests may also be carried out. Groundwater levels may be documented either by installing and monitoring piezometers or based on observations of groundwater seepages during and after drilling.

In addition to logging and characterizing the subsurface materials and groundwater conditions, the field investigation should focus on identifying conditions that could impact the feasibility of designing and constructing an HDD, including:

- the distribution/characteristics of surficial overburden deposits, in particular the occurrence of cohesionless clean silt-sand deposits and distribution and characteristics of any coarse-textured granular layers (*i.e.*, gravel, cobbles or boulders);
- depths to and nature of the bedrock formations, including the presence of hard and/or abrasive units (that could delay the project or impacts rates of wear on drilling equipment); and
- the presence of discontinuities, joints, fractures and fissures, that could contribute to instability of the bore during drilling and/or provide a path to the surface for drilling fluids.

6.2.4 Geophysical Surveys

When the results of bore hole investigations are inclusive or incomplete, use of shallow geophysical techniques may be considered. Seismic surveys, ground penetrating radar (GPR), electromagnetic (EM) surveys and electrical resistivity tomography (ERT) can be employed, often in combination. The application of geophysical methods is affected by the soil/bedrock conditions at the site and some techniques may not be appropriate in all situations.

Depending onsite conditions and expected subsurface materials, geophysical techniques can be used to supplement the bore hole investigation results. However, use of geophysical techniques as a substitute for, rather than as a complement to, bore hole investigations is not recommended. Past experience has shown that while geophysical survey results provide information along the entire drill path, from these methods may yield results that are ambiguous and difficult or impossible to interpret without "ground truth" information from bore holes.

Seismic Surveys

Shallow seismic surveys are mostly used to delineate the upper surface of the bedrock. Analysis of seismic survey data can also provide information on bedrock strength properties.

Ground Penetrating Radar

GPR is also used to delineate the upper bedrock surface but can also provide data on the distribution and characteristics of the overlying surficial overburden deposits. Unfortunately, due to the nature of the technique, GPR is unable to penetrate and "see" through clay layers of any thickness. Electromagnetic techniques can be used, in combination with GPR, to circumvent this shortcoming.

Electromagnetic Surveys/Electrical Resistivity Tomography

These techniques are also used to define and characterize the surficial deposits overlying the bedrock. They complement GPR due to their ability to "see through" clay layers in the subsurface, allowing the underlying materials to be defined and characterized. For this reason, EM and ERT are particularly useful for delineating buried sand-gravel channel deposits within the surficial overburden sequence. Since it requires good ground contact at frequent intervals, ERT is best suited to use during the summer.

6.2.5 Laboratory Testing

Laboratory tests that may be performed on samples returned from the field can include:

- moisture content determination on surficial overburden samples;
- Atterberg Limits on clays and bentonitic shales; and
- unconfined compressive strength tests on representative bedrock samples.

The laboratory test results should be presented on the bore hole logs that are appended to the geotechnical report (see below).

6.3 Geotechnical Report

A geotechnical report should be prepared, describing and presenting the results of the study, including an evaluation of the (geotechnical) feasibility of constructing the proposed HDD crossing. Based on the bore hole data and geophysical survey results, if available, an overall geological model of the ground conditions likely to be encountered along the bore can be developed.

The analysis and interpretation of the subsurface conditions encountered should concentrate on factors pertinent to design and construction of the proposed HDD installation, including:

- the occurrence of cohesionless and coarse granular surficial materials;
- the lithology and structural characteristics of the bedrock formations;
- data on groundwater levels and the presence of artesian conditions, if anticipated to be present;
- identification of overburden or bedrock intervals where loss of circulation may be a concern; and
- bedrock strengths.

Bedrock strength is often described in terms of the International Society for Rock Mechanics (I.S.R.M.) classification. Data on expected unconfined compressive strengths can be provided, either based on laboratory testing or estimated from the I.S.R.M. classification.

Bore hole logs and the results of laboratory testing should be appended to the report. The report should also be accompanied by a surveyed cross-sectional profile showing the soil and bedrock conditions encountered and the recommended No Drill Zone.

Issues that present a challenge to HDD design and construction, or that may affect the drilling contractor's assessment of the risks associated with completing a successful crossing, should be identified and discussed. Preliminary design recommendations, including the proposed No Drill Zone, expected entry/exit conditions and anticipated drilling considerations, should be provided.

6.3.1 Preliminary Design

A recommended No Drill Zone accommodating geotechnical and, if appropriate, hydrological and hydrogeological considerations should be developed for the crossing. As far as possible, the intention should be to maintain the bore within surficial overburden units or bedrock formations that are favourable for directional drilling. The No Drill Zone will typically be defined in terms of the minimum recommended depth of cover below the valley bottom, based on crossing area geometry, expected drill orientation, anticipated ground conditions, etc. and maximum entry and exit angles.

6.3.2 Entry and Exit Areas

The entry and exit areas for the proposed directional drill should be discussed, given the proposed drill orientation, "low to high" or "high to low" (wherever feasible, the former configuration is preferred), and expected near surface soil/bedrock conditions. Any requirement for casing to isolate the bore from gravels and other problematic materials on entry should be identified. Similarly, any need to excavate a bell hole at the exit to control drilling fluids and/or retrieve the drill string should be noted. Finally, an assessment of terrain conditions in the exit area for pipe stringing, welding and testing prior to pull back should be provided.

6.3.3 Drilling Considerations

Based on the description of the subsurface soil and bedrock conditions expected along the bore, issues pertinent to completion of a successful drill should be identified. These may include, for example, the possible occurrence of cobbles and boulders in till soils, presence of soils with fissures that could provide paths for fluid migration to the surface, high plastic clay soils and shale bedrock formations with potential for swelling, jointed/fractured bedrock units, etc.

7 ENVIRONMENTAL CONSIDERATIONS

HDD crossings are often undertaken to minimize the adverse environmental effects at watercourse crossings. Nevertheless, an HDD does not guarantee that all adverse environmental effects will be prevented. Common adverse effects are the result of:

- inadvertent returns of drilling fluids into the aquatic, terrestrial or social/cultural environments; and, to a lesser extent,
- disturbance of soils, vegetation, wildlife and social/cultural elements arising from either construction of drill sites, exit areas, access roads and temporary vehicle crossings, or the HDD activity.

Further details on the environmental effects of inadvertent releases can be found in many documents, including:

- Horizontal Directional Drilling Best Management Practices Manual, Topical Report. Gas Research Institute. May, 2002; and
- Quantifying the Effects of Sediment Release on Fish and Fish Habitats, Anderson, P.G., B.R. Taylor and G. Balch. 1995. Prepared for the Department of Fisheries and Oceans.

7.1 Aquatic Issues

A fish and fish habitat assessment of the water body to be crossed may be warranted to assess potential effects on these resources. Information from this assessment would be useful in prioritizing of containment / clean-up efforts in the event of an inadvertent release into a watercourse or in the preparation of appropriate mitigation / compensation plans if the HDD was not successful and another crossing method was necessary.

Adverse effects on the aquatic environment can result from the following:

- introduction of drilling fluids and mud into a watercourse, and any subsequent clean-up;
- poor surface runoff control from the drill site resulting in erosion and material entering a watercourse;
- disruption of aquifers that feed instream upwelling;
- improper water withdrawal;
- introduction of foreign or undesirable organisms from contaminated equipment; and
- spills of fuel or other hazardous material.

Potential effects on aquatic habitat and fish populations could include:

- HADD including instream, bank and riparian habitat at the crossing;
- elevated turbidity and increased deposition of sediment downstream;

- interruption of fish movements up or downstream;
- increased stress to individuals;
- injury or mortality of fish associated with improper operation and screening of water pump intakes;
- incidental mortality/injury associated with an accidental release of toxic substances through spills; or
- introduction of disease, parasites or other pests detrimental to fish.

7.2 Terrestrial Issues

Inadvertent returns and planned physical disturbance to the terrestrial environment during construction have the potential to adversely affect vegetation, wildlife and wildlife habitat, cultural resources, land use and nearby residents.

7.2.1 Vegetation

The primary potential effects on vegetation are as a result of:

- clearing of sites for drilling and access;
- damage to vegetation during clean-up from inadvertent returns;
- smothering and direct mortality of plants with drilling mud from inadvertent returns;
- creation of a nearly impenetrable layer of clay on the surface preventing germination or colonization of new plants from inadvertent returns;
- change in surface soil characteristics, thereby creating a change in vegetation communities; and
- creation of a subsurface deposit resulting in an upheaval that changes hydrologic or soil moisture regimes, in turn affecting the vegetation community.

7.2.2 Wildlife

The primary potential effects on wildlife habitat and populations as a result of inadvertent returns or from planned activities include:

- interruption of wildlife movements as a result of general construction activity associated with the HDD;
- loss of riparian or wetland habitat as a result of inadvertent returns of drilling mud;
- direct mortality of amphibians, reptiles, invertebrates and other less mobile wildlife from inadvertent returns;
- increased stress to wildlife species reliant on adversely affected critical habitat; and
- incidental injury/mortality associated with accidental release of toxic substances through spills or, in some cases, additives to drilling mud.

7.3 Social and Cultural Issues

Potential adverse effects on communities, land use and cultural resources can result from the following causes:

- release of drilling fluids and mud into culturally or socially sensitive areas;
- spills of fuel or other hazardous material;
- noise or vibration from HDD site preparation or construction activity; and
- disruption of aquifer use for domestic or agricultural purposes.

In particular specific issues could include:

- destruction of archaeological sites (often associated with watercourses); and
- disruption of current land use including disturbance of nearby residents.

7.4 Site Investigations

Environmental site investigations are not critical to the determination of the feasibility of HDD. However, these site reconnaissances and surveys should be undertaken in situations where there is a risk that any of the following may be present:

- fish and fish habitat within the potential zone of impact (*e.g.*, up to several thousand metres downstream on a fast moving watercourse);
- rare and endangered plant or wildlife species in the vicinity of the HDD entry or exit points;
- critical habitat that would need restoration to pre-disturbance levels in the event of an inadvertent release;
- archaeological sites; or
- nearby residents.

Site investigations should be undertaken in advance of the HDD to ensure that there is sufficient baseline data to provide a bench mark for future clean-up or reclamation activities.

8 ENGINEERING DESIGN CONSIDERATIONS

8.1 Design of Drill Path

The design of the drill path should consider all of the information gathered for the crossing area. The physical limitations of the site as well as geotechnical, environmental (fish, wildlife, vegetation, land use, cultural) and hydrological information should be considered in the preparation of the drill path design.

8.1.1 Limitations of HDDs

The feasibility of HDDs is dictated by the length of the bore hole to be drilled, the diameter(s) of the pipe string, as well as the subsurface soil/bedrock conditions. As of 2000, the longest drilled crossings have been recorded at approximately 1,800 m, with small diameter pipe. The largest pipe diameter to be drilled as of 2000 was a 1,219 mm O.D. project. HDD crossings with such a large diameter pipe are rare. Entry angles of HDDs vary from 8 to 18 degrees from horizontal, with longer crossings having a longer horizontal segment at the specified depth of cover. HDD equipment can adjust for different entry angles. [*Editors Note: Newer stats to be researched*]

Existing HDD technology (*i.e.*, rig tools and drill pipe) and economic considerations are the primary factors limiting drill path length and pipe string diameter. The flexible nature of drill pipe limits the amount of pressure that can be applied to the drill string and, therefore, control of the front of the drill string decreases over longer bore lengths. The capacity of the drill pipe to transmit torque from the rotating surface to the down hole reamers is also a limiting factor.

Emergence of new HDD technologies to confront drill path length and product pipe diameter restrictions is also influenced by economics. The installation of large diameter pipe over long lengths is rare and the market for such technologies is small, thereby limiting the funding and research needed to acquire these new technologies.

The nature of the subsurface soil and bedrock materials at a proposed crossing is one of the primary geotechnical limitations to the installation of a pipeline using an HDD. A high proportion of coarse-grained materials (*e.g.*, gravel, cobbles and boulders) as well as excessive bedrock strength and hardness are the main subsurface characteristics that may impair the use of HDD. Coarse-grained soils are not readily fluidized by drilling muds and can present a serious constraint to the feasibility of an HDD if encountered. Boulders or clusters of cobble remain in the drilled path and present an obstacle to the bit, reamer as well as the pipeline, while excessively hard rock makes all phases of the HDD difficult.

Extensive fracturing or jointed rock can present problems similar to those encountered with coarse granular deposits. Competent rock with an ideal unconfined compressive strength of approximately 15,000 psi (103 MPa) and a hardness, based on Moh's Scale of Hardness, greater than 7 can be negotiated with an HDD, given today's technology. One problem often encountered when facing such characteristics at depth is the tendency of the drilling string to deflect rather than penetrate the subsurface.

8.1.2 Depth of Cover

Depth of cover requirements are dependent upon a number of factors such as subsurface conditions, type of drilling equipment, mud pressure (which is a function of the mud pump capacity), and the difference in elevation between the entry and exit points. Depth of cover is a factor used in the development of the No Drill Zone (Section 3.4.3) and should be determined by the HDD project team.

8.1.3 Entry and Exit Points

Considerations related to the entry and exit points have previously been discussed in Section 3.4.2.

8.1.4 Alignment

Angles in the easement/right-of-way alignment adjacent to an HDD crossing should be minimized. If difficulties are encountered during an HDD, it may be necessary to increase the drill length. Therefore, the entry and/or exit points would need to be moved farther back from the location being crossed. The approach alignment to the HDD crossing needs to allow for the potential need for lengthening of the crossing.

8.1.5 Right-of-Way

The drill path should be aligned to lie within the right-of-way boundaries. If this is not feasible, new right-of-way must be acquired prior to commencement of the HDD. Temporary workspace is typically required at a crossing above and beyond that necessary for conventional pipeline construction. As discussed in Section 1.2, temporary workspace is required at the entry and exit points. The pipe string will require additional workspace and, where the alignment on the exit side is not straight, additional workspace, typically referred to as false right-of-way, may be required. This area should be of sufficient length and width to allow the pipe to be welded up and tested along the full length of the pipe string. It is highly recommended that the pipe string be fabricated in one complete section since any stoppage in pulling of the pipe string adds significant risk to the success of the project.

8.2 Land Issues

The land issues listed below should be considered during the planning phase of an HDD project:

- landowner consultation during the routing and crossing selection process, and when determining a water source for drilling activities;
- landowner consultation when determining access to the water source;
- landowner consultation to avoid conflict with land use practices (*e.g.,* drill in pasture when cattle have been rotated to another pasture or during the winter to avoid the crop year);
- informing the landowner of HDD processes and applications to avoid potential issues;
- landowner consent for access across lands not on the right-of-way for monitoring purposes and potential reclamation of inadvertent returns;
- spills on the entry side and the pipe side of the drill may require reclamation and remediation as well as compensation to landowner and compensation for any habitats lost; and
- trespass off the right-of-way due to inadequate marking of designated work areas or inadequate location or amount of workspace.

8.3 Casing

Contractors often use a short section of casing that is 'dug in' at the start of construction. This casing is intended to prevent inadvertent near-surface returns, and allows for easy monitoring of drilling mud return levels. However, where unconsolidated deposits represent a risk of inadvertent returns on the entry side, the casing may need to be more extensive. The casing can either be driven in with a large hydraulic hammer or, possibly, in softer soils, pushed in with the drill rig.

Casing should be of sufficient length to seal into a suitable competent formation such as bedrock or cohesive stiff clay. The casing diameter should be greater than the final reaming pass to ensure down hole tools can easily enter the bottom of the casing throughout the entire drilling operation and pull back.

It is preferable to remove any casing at the end of the crossing construction since it will shield the pipeline within the crossing from cathodic protection.

8.4 Pipe

8.4.1 Type

Tensile and bending stresses that are induced on the pipe during an HDD installation should be analyzed to ensure the pipe is suitable for installation. This analysis is especially important when using thin wall steel pipe or plastic pipe.

8.4.2 Number of Pipes

In many instances it is proposed to install more than one pipe in the drilled crossing. The characteristics to consider are the size of the pull head, number of pipes, as well as the size of the individual pipes, including pipe coatings. These items will increase the final bore diameter and will dictate the minimum radius of curvature.

8.4.3 Coating

As mentioned in Section 4.3, one operational risk that should be addressed is external corrosion due to damaged pipeline coatings. Protective coatings can often be damaged during pull through by the forces involved, and by contact with soils, rocks, and other debris present in the bore hole. The consequences of coating damage are multiplied by the nature of the HDD method. A pipeline installed by HDD will not be readily accessible to make future pipeline or coating repairs.

External pipe coatings for HDDs must be carefully selected to minimize the risks. Given the potential for coating damage it may be necessary to select a different coating system for the HDD section(s) of a pipeline.

Coatings used for HDD drag sections must be flexible and have sufficient abrasion resistance to limit damage. The economic and environmental consequences of a future failure are significant. Cathodic protection (CP) compatible coatings will allow protective current to reach the pipe regardless of any damage to the coating. Certain coatings such as single or double layer extruded polyethylene, or polyethylene tape, can shield cathodic protection current when damaged. Such coatings should be avoided on HDD projects.

Often the most suitable coatings for an HDD project are Fusion Bond Epoxy (FBE) or similar liquid coatings. An additional layer of pipe coating should be applied for abrasive protection. This layer is often referred to as the abrasion resistant layer or the sacrificial layer. The exact type of coating should be selected based on a number of factors including the amount of abrasion expected.

The selection of field applied joint coatings also requires careful attention. It is recommended that the joint coatings be liquid epoxies with similar properties, especially abrasion resistance, as the main plant applied coating. Since the joint coatings are field applied, proper application methods, qualified workers/applicators, and qualified coating inspectors are recommended.

In addition to inspecting the coatings during the actual application process, a careful visual inspection should be made of the first few pipe joints at the exit location. Often these leading joints are believed to receive the most damage. If these joints are in good condition it is likely that the remaining coating is in similar, or even better condition.

Another method of inspection is an in situ electrical method to determine the coating resistance. A competent cathodic protection technician can complete this work. This type of inspection can provide a relative understanding of the coatings efficiency. The field CP measurements must be done prior to completing any tie-in welds to the rest of the overland pipeline. Therefore, the timing of this work must be carefully coordinated.

Conventional two-layer extruded polyethylene coatings are not recommended due to their susceptibility of damage, and possible shielding of cathodic protection current. More recently available three-layer polyethylene coatings (FBE coating with a polyethylene topcoat) may be considered.

External concrete weight coatings are not recommended due to their brittleness, weight, and high coefficient of friction.

Further information is available from many sources including coating manufactures and NACE International publications such as:

- Design and Coating Selection for Successful Completion of a horizontal Directional Drill (HDD) Crossing. A.I. Williams and J.R. Jamison, NACE CORROSION/2000 Paper

8.4.4 Insulation

It is typical for some pipe to be specified with a thick layer of insulation. This will necessitate the final ream to be larger than an uninsulated pipe.

8.4.5 Limits of Curvature

The design of the drill path and selection of pipe must consider the following:

- the radius of the curves in the drill path; and
- the exit and entry angle.

The radius of the arc of the drill path should consider the diameter of pipe to be installed. The minimum radius for most drilling applications is:

- the diameter of the pipe to be installed in metres multiplied by 1200; or
- the pipe diameter in inches multiplied by 100 to obtain a radius of curvature in feet.

This formula is used to ensure a conservative radius of curvature that will allow for the easy installation of the pipe and minimize the bending stresses on the pipe. If the pipe is smaller than the drill string, the larger pipe size shall be used in the minimum radius calculations. This will ensure that the drill pipe will not be overstressed and the drill can proceed as planned. In most applications, the radius of curvature will not be lower than 250 m.

8.5 Drilling

8.5.1 Reaming Diameter

The general “rule of thumb” is to ream the drill hole to 1.5 times the outside diameter including coating and insulation of the pipe to be installed. This diameter will generally provide for an adequate allowance for the installation of the pipe. The multiplier may be reduced for large pipe diameters (>36”/914 mm O.D.)

The number of reaming passes that will be determined by the hardness of the material being reamed and the ability to remove cuttings from the hole.

8.6 Testing

As noted in Section 3.4.4, the pipe string is often hydrostatically pretested prior to pull back. This segment of pipe is then also tested as part of the mainline pressure test. Pretesting and testing of the installed pipe upon completion of the drill should follow CAPP’s 1996 *Guidelines for Hydrostatic Test Water Management*.

9 CONTRACTUAL CONSIDERATIONS

9.1 Types of Contracts

Prior to tendering an HDD, the owner needs to determine if this particular aspect of their project warrants special attention. Since this part of a project may present a high risk, it may be necessary to tender the HDD outside of the general pipeline contract. Upon determination of the specifics required for the project, a variety of contract types should be considered when packaging an HDD tender: unit price; lump sum; target price; daily rate; and cost plus. Depending on the quantity and quality of the available geotechnical information, perceived risk etc. a certain type of contract will suit specific crossings.

9.2 Contractual Issues Related to HDD

Contractors bidding on HDD jobs should be provided with as much information as possible from the owner company to facilitate the preparation of an accurate and comprehensive cost proposal so that the project, once awarded, can be completed as planned with very little dispute. Other advantages of owner companies providing adequate information to their contractors for bidding purposes are that it allows the project to be conducted in a safer manner and with reduced potential for environmental impacts. Once the cost proposal is accepted by an owner, the proposal becomes a binding contract between the contractor and the owner company.

As with any contractual relationship between a contractor and owner company in the construction and/or petroleum industry, contracts for any HDD project should be written agreements that both parties comprehend. Within the contract, the project must be defined and the scope of work should be detailed as precisely as possible. All plans and specifications should be incorporated into the contract. The parties to be involved in the project, price to complete the project and project performance should also be specified in the contract. Workable mechanisms should be written into the contract so that adjustments relating to schedule as well as cost can be made if difficulties or unforeseeable circumstances (*e.g.*, weather, varying geotechnical conditions) are encountered that affect the scope of the project. Since no two HDD projects are the same, contracts should clearly indicate unit prices as well as add and/or delete clauses identifying factors that could potentially change rates and overall costs. Terms of payment should be clearly addressed in the contract and payment options affecting the bid price should be taken into consideration. Late payment options and early payment discounts may also be identified within the contract. Table 2 identifies specific elements that should be given particular consideration in the contract.

9.2.1 Geotechnical Investigation

the geotechnical report containing geotechnical, geological and other information acquired during the feasibility study (*e.g.,* geophysical survey results) and including a proposed No Drill Zone (with or without a description of the design drill path), should be provided to the contractor for determining a contract price for the drill.

since unknown or unexpected ground and subsurface conditions may occur during the course of the drill, mitigation upon encountering differing ground conditions should be included in the contract.

9.2.2 Existing Underground Utilities

The owner should locate all existing utility lines and identify them in the bid package, since they may affect the drill path and No Drill Zones;

The contractor should be obligated, upon conditions set forth in the contract to have an onsite verification performed prior to the drill, the liability should be placed on the contractor for marked utilities while the liability should be placed on the owner for unmarked utilities;

General liability insurance should be carried by the contractor ensuring the insurance covers underground collapse and explosions

9.2.3 Documentation / As-builts

As-built drawings and a summary as-built report should be completed based on down hole survey data or the walkover location system;

As-built drawings and the as-built report will protect the contractor and owner from future problems (*e.g.,* future projects in the same area);

The drawings should have calculated x, y and z positions every 10 m (or other interval identified by the owner) along the alignment

9.2.4 Access

It should be the owner’s responsibility to acquire access to the drill site prior to construction, since it is the owner that will have a long term relationship with landowners affected by the right-of-way or construction works;

All access agreements relevant to the hdd project should be provided to the contractor prior to construction

9.2.5 Equipment

The bid documents should identify the equipment and respective equipment specifications to be assigned to the project

9.2.6 Environmental Concerns

Owners and contractors are potentially liable if environmental damage occurs and clean-up/compensation costs.

Environmental concerns should be identified in the contract and a mitigation plan should be in place for the project.

Federal, provincial, territorial and local approvals should be reviewed and all conditions must be followed.

Water turbidity (*i.e.,* at water crossings) as well as inadvertent release of drilling mud are relatively common problems associated with HDDs and are difficult to predict; the contract should address and provisions should be included to mitigate these problems, since the contractor and owner company often share liability.

9.2.7 Allocation of Risk of Loss

Risk of loss that may occur during the course of the project should be predicted and assessed in the contract.

Owners should share the risk of loss with the contractor since the bid price is affected by unanticipated losses.

Insurance may be available for losses due to differing ground conditions or environmental issues.

9.2.8 Dispute Resolution

Alternative Dispute Resolutions (*i.e.*, arbitration or mediation) should be incorporated into the drill contract and disputes ideally resolved in the following order:

- negotiation in good faith;
- nonbinding mediation through a third party;
- binding arbitration; and/or
- litigation.

Provisions for termination, indemnification and payment terms should be clearly addressed in the contract and understood by the contractor and owner.

9.3 Pre-qualification of Bidders

If practical, bidders should be pre-qualified to ensure that they have adequate equipment, experience, personnel and specific company experience in the area of the crossing.

9.4 Drawings

In order to ensure accurate bids, the limiting parameters for a design drill path should be identified. The proposed drill path should be presented on the drawing profile along with the "No Drill' Zone and any geotechnical information, including the geotechnical report, that is available (see Section 6.3).

9.5 Sharing of Risk

HDD crossings present an inherently much higher risk than standard pipeline construction. Where possible, this risk should be mitigated by providing adequate site information such as geotechnical information. Specific contract types are in effect "shared risk" contracts and the use of these types of contracts should be considered.

9.6 Responsibilities of Parties

Specific responsibilities pertaining to the parties involved with the HDD should be clearly explained in the contract. Such responsibilities that should be included in the contract are:

- responsibility for arranging the surveying and staking of the access and entry and exit points of the drill should be clearly identified;
- the owner company should clearly state any reporting schedules and/or systems that the contractor(s) are to follow during the course of the drill (*e.g.*, phone in daily progress reports to the project manager);
- monitoring and contingency responsibilities should be clearly defined;
- the contract should specify who is responsible for the accumulation of extraordinary costs during the course of the project; and
- it should be clearly stated what each of the parties is responsible for providing, and whether separate pricing is required for specific items.

9.7 Failed Crossings

HDD projects can fail in a number of ways (see Section 10.3), including:

- unexpected geotechnical conditions that preclude the successful completion of the HDD;
- the drag section is difficult to pull back through the crossing;
- the pipe gets stuck in the hole after a successful drill and ream; and/or

- inability to prevent excessive inadvertent releases and after all possible attempts are made, the cost becomes unacceptably high and the HDD may be deemed unfeasible.

Parts or all of the down hole assembly may be lost during a failed attempt and payment for these should be addressed in the contract documents. It is technically feasible to “fish” for the equipment left down hole, however, the cost and possibility of success should be weighed against the value of the down hole equipment. These types of failures should be considered when designing the crossing and preparing the tender documents.

Since there is potential for an HDD to fail, it is imperative that alternate crossing plan(s) be prepared in advance in order that approvals have already been received or may be obtained in a timely fashion in the event of a failure.

9.8 Dispute Resolution

All contracts should contain details on how disputes will be resolved. Consideration should be given to incorporating Alternative Dispute Resolutions (*i.e.*, arbitration or mediation) into the contract.

9.9 Drilling Execution Plan

The selected contractor should develop and present to the owner a written drilling execution plan that addresses all aspects of the HDD. A full list of components of the plan is provided in Appendix C. Key topics in the plan include:

- details of each step of the HDD;
- detailed drawings;
- equipment specifications;
- workspace and water requirements;
- monitoring plans including frequency and type; and
- contingency plans.

9.10 Environmental Protection Plan

An environmental protection plan (EPP) should be developed by the owner to address mitigative measures to be implemented during execution of the HDD. Environmental protection planning should cover all aspects of the execution of the HDD including land, water and access needs. The EPP should address the following aspects and be closely linked to the drilling execution plan:

- notification and approvals;
- identification of environmental exclusion areas to be incorporated into No Drill Zones;
- environmental and social timing constraints;
- equipment inspection and servicing;
- clearing and grading of HDD sites and access;
- erosion and sediment controls; and
- monitoring.

In addition to having an EPP, it is essential to have qualified people onsite to enact the plan, to handle deviations to the plan and to report events properly to the authorities. Having an environmental specialist or biologist onsite to liaise directly with the DFO habitat biologist or other similar authority can prove useful. Effective communication of unintended events and subsequent mitigation actions to the authorities may reduce delays or unwarranted enforcement actions contingency planning, *e.g.*, inadvertent returns, (see also Section 10.3.2); and reclamation.

10 CONSTRUCTION CONSIDERATIONS

10.1 Drilling

10.1.1 Types and Sizes of Rigs

The size of HDD rigs can vary substantially. This range in sizes should be considered when planning and developing specifications for an HDD project.

In general, rigs are sized according to their available pull force and rotary torque that can be applied to the drill stem and pipe string.

The following are samples of rig sizes and the respective ranges of projects that can be completed.

Rig Torque	Length of Drill	Diameter of Pipe
0 – 54,000 Nm	up to 200 m	up to 168.3 mm
54,000 – 108,500 Nm	up to 400 m	up to 273.1 mm
108,500 – 217,000 Nm	up to 500 m	up to 323.9 mm
217,000+ Nm	over 500 m	over 323.9 mm

Note: Nm = Newton metres

The capabilities of each rig should be assessed for each project. The assessment of rig capabilities should take into account the possibility that formations or other subsurface materials may be encountered that could cause difficulties with the HDD project.

10.1.2 Casing

Considerations related to casing are discussed in Section 8.3.

10.1.3 Drag Section

The pipe installation should be designed so that, wherever possible, the pipe string or drag section can be laid out and pulled back in one continuous section.

The pipe will have to be lifted into place to match the exit angle of the drill to allow the drill rig to pull the section into place.

The pipe string is usually placed on rollers as it is pulled into the drilled hole. The drag section may be cradled through a vertical curve to achieve the proper angle at the exit point. This curvature should be no more than the limiting curvature of the pipe.

10.1.4 Steering / Survey of Drill Head

It is necessary to 'steer' the drill head or mud motor during the drilling of the pilot hole. A number of steering technologies are available. Two of the more common systems are known as the DigiTrak system and the TruTracker® system. The DigiTrak is a "walkover system" that is somewhat limited in the depth to which it is effective. The TruTracker® system is a "wireline steering tool system" and is utilized where the depth of the crossing is outside the range of the walkover system. Both of these systems provide effective steering.

10.1.5 Drilling Fluids

Drilling fluid is used for a number of tasks in the HDD process including:

- cooling and lubricating the drill stem, mud motor and bit;
- providing hydraulic power to the mud motor which in turn converts hydraulic power to mechanical power;
- carrying cuttings out of the bore hole;
- stabilizing the bore hole during the drilling process; and
- sealing fractures in the formation.

Drilling fluid is usually a mixture of freshwater and bentonite. Bentonite is naturally occurring clay that is extremely hydrophilic (*i.e.*, has high swelling characteristics). Certain polymers may also be used that enhance the drilling fluid benefits.

A drilling fluid design plan should be established before the start of the project. This plan should also be modified, when warranted, throughout the project to ensure the drilling fluid is fulfilling its function.

The contractors' drilling execution plan should identify the equipment to be maintained onsite to check drilling fluid properties. Alterations to the mix should be made, when warranted, to stay within the proposed boundaries in the drilling fluid management plan.

A mud handling system should be onsite to ensure drilling fluid parameters are within the set standards.

Appendices D and E, respectively provide a pipe volume table and conversion factors that may be of use in the calculation of drilling mud volumes or other aspects of an HDD project.

Additives

Various chemical and materials can be added to the drilling fluid to adjust its properties. This is done to control:

- density;
- viscosity;

- plugging and sealing capabilities; and
- specific conditions such as swelling.

All additives should be environmentally safe. A number of additives have been recognized as safe for the water well drilling industry and, with the proper approvals, could be used for the HDD industry. All additives must be approved before use.

10.1.6 Drilling Fluid Disposal

Samples should be acquired of the drilling fluid/cuttings and analyzed for contamination before disposal. Permits/approvals are required in some provinces and territories for the disposal of drilling wastes.

Drilling fluid and cuttings can be disposed of in three ways:

- mix and bury onsite;
- land spread; and
- haul to an approved site or disposal facility.

10.1.7 Buoyancy Control

When a drag section is pulled back through the bore, the buoyant weight of the pipe as well as the resulting drag forces between the pipe (pipe coatings) and the walls of the bore will act as resisting forces. The drag force can be severe enough to damage pipe coatings as well as collapse the pipe. Therefore, it is important to determine during the planning phase whether buoyancy control is needed. If buoyancy control is necessary (*i.e.*, for some long and large diameter drills), a buoyancy control plan needs to be implemented. Typically, buoyancy control is applied by adding water to the drag section during the pull back phase.

10.2 Monitoring

Monitoring and reporting are critical during an HDD since they provide a log of activities during the process to:

- provide early identification of issues;
- make appropriate changes;
- provide a basis for mitigation; and
- provide a record of decisions and actions to demonstrate due diligence.

It is important to ensure that sufficient records are maintained before, during and after construction to support subsequent reports prepared to satisfy contractor, owner or government reporting requirements. This should include detailed notes and photographs of all areas monitored.

10.2.1 Drilling

The following monitoring and reporting activities should be reviewed for appropriateness for the size and complexity of the HDD crossing:

- inspector daily records – a day-to-day account of the entire construction of the project;
- contractor drilling records;
- steering report;
- drilling fluid volume balance report;
- drilling fluid parameters;
- drilling fluid additives list;
- annular pressure modeling and reporting;
- turbidity monitoring report;
- surface monitoring report;
- pull force monitoring; and
- inadvertent return report.

10.2.2 Environmental

An environmental monitoring and response plan should be prepared by the contractor to address all the issues outlined in the EPP or specific concerns in the permits.

The drill path and surrounding area should be monitored up and downstream of the works. Where pressurized drilling fluids are used, monitoring should extend at a minimum 400 m up- and downstream of the crossing, and be conducted on a fixed interval basis as identified in the EPP. The exact distances will depend on the various issues at the site. Monitoring should be documented and any evidence of fluid on the surface should be reported to the owner and appropriate provincial, territorial and federal authorities as soon as possible.

Large water bodies and water bodies that are crossed when ice cover is present may warrant turbidity monitoring to identify whether inadvertent returns are entering the water body. The water body turbidity should be monitored regularly to ensure that a loss of fluid in the water body is detected as early as possible. The sample locations and sampling protocol including method and frequency of sampling, (including frequency under normal operating conditions and when loss of circulation occurs) and acceptable turbidity rates should all be determined in advance of the works by an aquatic specialist and specified in the EPP. The monitoring must be documented and any evidence of increased turbidity levels should be reported at once.

If a loss of circulation occurs during the drilling program, the frequency of monitoring should increase to detect any inadvertent returns to surface.

10.2.3 Indicators of Inadvertent Returns

Inadvertent returns occur when drilling fluids disperse into surrounding soils or randomly discharge to the surface. Such inadvertent returns are a result of the drilling fluid following the path of least resistance. To help prevent such releases the drill path should be aligned to avoid or minimize soils or formations prone to inadvertent returns, casing at the entry hole may be installed and other drilling parameters are established to maximize drilling fluid circulation and minimize the potential for unintentional drilling fluid returns. Conditions where inadvertent returns have a higher potential to occur include:

- fractured rock (pre-existing flow paths or presence of joints);
- coarse grained permeable soils (gravel, cobble and boulders);
- considerable elevation differences between the entry side and pipe side;
- areas where HDD vertical depth of cover is insufficient; and
- artifical features (existing exploratory bore holes).

10.3 Failures

10.3.1 Types and Causes

Many of the more common types of failures and their associated cause(s) are noted below in Table 2.

Table 2 - Types of HDD Failures and Their Cause

Type	Cause
Loss of drilling fluid / Loss of circulation	• permeable deposits or jointed and/or fractured bedrock along the drill path • excessive annular pressures for the bedrock formation or soils encountered
Drilling mud seepage directly into watercourse	• permeable deposits or jointed and/or fractured bedrock along the drill path • excessive annular pressures for the bedrock formation or soils encountered
Drilling mud seepage onto land and then into watercourse	• permeable deposits or jointed and/or fractured bedrock along the drill path • excessive annular pressures for the bedrock formation or soils encountered • suggests inadequate monitoring along drill path
Collapsed hole	• erosion or settling of the bore hole
Stuck drill stem or pipe string	• collapse of hole along the drill path, due to swelling of highly plastic clays, boulders, bentonic shales, coal seams • inadequate reaming to obtain optimal bore diameter for pull back
Lost tools and/or drill stands	• twisting off of drill stem or metal failure of down hole tools

Type	Cause
Damaged pipe or coating	• inadequate reaming to obtain optimal bore diameter for pull back • excessive entry or exit angle for bend radius of the pipe string • sharp objects or casing present in bore • collapse of hole along the drill path

10.3.2 Contingency Plans

A site-specific contingency plan should be prepared by the project team for each HDD. A well designed contingency plan should address the following:

- general measures;
- equipment and personnel needs for containment and clean-up;
- emergency response procedures;
- plans for continuance of drilling or alternative plans;
- time lines of acceptable response and notification;
- clean-up methods and plans;
- regulatory and stakeholder contacts;
- monitoring plans; and
- disposal plans.

Appendix E provides one example of a contingency plan.

10.3.3 Selection of Alternatives

Alternatives that may be available to allow continued use of an HDD method following an initial failure include:

- down hole cementing to either seal off the problem zone for redrilling or seal off a large portion of the existing bore hole to a point where a new drill path (generally at a lower elevation) can be attempted; note that if reaming is necessary this method may not be successful since any reaming will remove localized cementing
- a new drill can be attempted at a steeper entry angle in an attempt to get below the problem area
- the drill can be moved and an attempt made to redrill from a new location (the revised drill path should be reviewed and revised accordingly prior to drilling); and
- the feasibility of conventional (*i.e.*, trenched) crossing methods should be considered if the drill fails; consult the appropriate project staff as well as regulatory authorities.

10.3.4 Clean-up and Remediation

An important decision may be required when developing plans to clean-up an inadvertent release of drilling mud. The decision can involve determination of whether or not clean-up and reclamation of a site will incur greater adverse effects on the environment than leaving the mud *in situ* and allow natural processes to reclaim the area. In some situations, a combination of minimal intervention and letting nature take its course can also be appropriate (*e.g.,* re-establishing a channel in a blocked wetland while leaving the wetland to reclaim itself).

The determination as to whether to clean-up or not must be made in conjunction with appropriate regulatory and land authorities. In many cases, this decision will be contrary to traditional practices and must be made after thorough examination of the advantages and disadvantages of each.

The potential environmental impacts associated with HDD are addressed in Section 7.0.

Clean-up of Returns

The impacts from clean-up activities in sensitive environments are dependent upon the level of activity and equipment required to remove the residual drilling mud, terrain and aquatic conditions and season.

Containment

Several containment measures are commonly used for the uncontrolled release of inadvertent returns (Table 3). The measure(s) chosen to be used depend upon:

- the anticipated volume to be contained;
- existing access to the site;
- environmental sensitivity of the area contaminated and adjacent areas; and
- soil and weather conditions

Table 3 - Containment of Inadvertent Returns

Containment Measure	Conditions Used / Application
Silt fencing	• controls migration of drilling mud in wetlands; • retains small volumes of sediment; • decreases overland flow of drilling mud and fluids; • minimizes total suspended sediment quantities of surface waters through filtration; • suitable for wetlands and the banks and shorelines of water bodies

Containment Measure	Conditions Used / Application
Hay or Straw Bales	• retains small volumes of sediment; • decreases velocity of downslope runoff; • suitable for vegetated wetlands, and the banks and shorelines of water bodies
Sand Bags	• contains high volume inadvertent returns by creating a dam; • used where silt fences and bales are not effective
Floating Booms	• contains drilling mud in areas with a high flood potential where drilling mud returns may be spread by water flow throughout a water body; • suitable in water bodies where water level exceeds 30 cm
Plywood Sheets	• contains deeper pooled inadvertent returns; • suitable for water bodies where clean-up of returns cannot be completed before water flow disperses the returns
Culverts	• large culverts can be installed vertically over an instream point source release to contain released fluids and facilitate clean-up activities
Aquadams	• useful in diverting streamflow from an area of release or isolating the release area

Clean-up

It is important for the owner, contractor, appropriate environmental specialist(s), if warranted, and appropriate regulatory agency to discuss the clean-up goals for a site subjected to an inadvertent release of drilling fluids prior to commencement of clean-up activities. If a net gain is not anticipated as a result of clean-up, alternative measures may need to be implemented. Vehicles and equipment commonly used during the clean-up of a mud release are identified in Table 4.

Table 4 - Potential Equipment and Vehicles Used During Drilling Mud Clean-up

Equipment	Use
Backhoe	• for executing containment pits at drill sites situated in upland areas
Vacuum trucks	• for the immediate collection of drilling fluids for recycling or off-site disposal; • ground low-pressure tires may be placed on vacuum trucks to reduce footprint in sensitive areas
Dump trucks	• for removal of drilling mud to disposal areas, if required

Equipment	Use
Frac tanks	• for above ground storage of drilling fluids and to contain inadvertent returns prior to disposal; • minimizes overall disturbance to the site, since sump pits are not required
Swamp mats	• for minimizing sedimentation caused by heavy traffic in waterways; reduces compaction and rutting by heavy equipment in areas of wet terrain during nonfrozen conditions
Plywood sheets	• for use as walk ways for crews in sensitive areas, reduces footprint to the site
Brooms, rakes, spades and shovels	• for manual removal of muds from vegetated areas, for use after majority of muds are cleaned-up by larger equipment
Squeegees	• can be useful in removing residual mud from vegetation, thin residual mud so that vegetation is able to break through the mud layer
Snowshoes	• useful for workers to access areas with thickly pooled released drilling mud to assess final clean-up requirements where heavy machinery is not allowed; • reduces impact of foot traffic on vegetation
Water rinse	• softens hard or dry drilling mud

10.4 Reporting

10.4.1 Monitoring Reports

Prior to the start of construction, the contractor should be required to provide the proposed monitoring report forms as part of the drilling execution plan. Frequency and types of monitoring should also be presented in the drilling execution plan.

10.4.2 As-Built Reports

As part of project deliverables, the contractor should provide the owner an as-built drawing in a format approved or determined by the owner. The contractor should also provide a set of the monitoring reports at the end of construction.

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APPENDICES

Appendix A Glossary

Appendix A - Glossary

annular pressure	*fluid pressure acting on the formation measured in the space between the drill stem and the wall of the bore*
arc	*curved section completed at a predetermined radius of curvature*
Atterberg Limits	*the water content of a soil when it passes from a semi-solid to a plastic state and from a plastic to a liquid state; and can be empirically correlated with clay content and its propensity to swell.*
bentonite	*a clay mineral, primarily montmorilonite, with high swelling properties that forms the primary component in drilling muds used in HDDs*
bottom hole assembly (BHA)	*tools used in directional drilling including the bit, bent sub, mud motor, steering tool, annular pressure tool, and connections to provide directional control, information gathering and drilling power*
bore	*earth removed from between the surface entry and exit points along the drill path*
casing	*pipe installed through problematic near surface materials such as gravels and cobbles to provide a conduit for the BHA and other down-hole tools and drilling fluid*
deleterious substance	*any substance that would degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to the use by man of fish that frequent that water;*
	any water that contains a substance in such quantity or concentration, or that has been so treated, processed or changed, by heat or other means, from a natural state that it would, if added to any other water, degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to the use by man of fish that frequent that water
drill stem	*steel drill pipe approximately 10 m long and 114.3 to 168.3 mm O.D., used to control and transfer fluid in an HDD*
drill bit	*a device that cuts into the formation and progresses the bore*

drill cuttings	*ground and subsurface material broken by the drill bit*
drilling mud/fluid	*fluid created by mixing water and bentonite as well as other additives to facilitate drilling and transport of drill cuttings from drill bit to the surface*
down-hole tool	*tools that are used at the end of the drill string to physically complete the bore and to provide directional and other information*
entry point or rig side	*the side of the HDD where the drill rig is situated and where the pilot hole is started*
exit point or pipe side	*the side of the HDD where the pilot hole exits the crossing; where the pipeline to be installed into the bore is fabricated*
harmful alteration, disruption or destruction (HADD)	*HADD of fish habitat is defined by DFO as "any change in fish habitat that reduces its capacity to support one or more life processes of fish."* *HADD applies when determining if or whether any of the three conditions (i.e., harmful alteration, disruption, and destruction) are likely to result from a project.*
hydraulic fracture	*the process of annular pressure inducing a fracture or opening up an existing fracture in the formation during the drilling process*
inadvertent return	*drilling fluid and cuttings that migrate from the drilled hole to the surface, along a joint, fracture or any other path of least resistance*
measured depth	*total bore length as measured from the surface to the lowest point on the drill path*
Moh's scale of hardness	*a scale of hardness devised to aid the identification of minerals*
mud motor	*mechanical device that transforms hydraulic power to mechanical power to turn the drill bit and maintain the progress of the bore*
No Drill Zone	*upper limit of the drill path as defined by the geotechnical engineer, between potential or specified entry and exit locations. Intended to ensure the bore is maintained within geological formations suitable for directional drilling with suitable cover to assist in minimizing the potential form inadvertent returns.*
pilot hole	*the initial bore drilled along the drill path*
pipe string	*pipe to be installed through the bore at the completion of the HDD drill to carry product through the crossing*

radius of curvature	*the bend radius of the drill or pipe string*
reaming pass	*subsequent pass(es) through the pilot hole to increase the diameter of the pilot hole to the required size to accomodate pipeline pullback*
small HDD project	*generally an HDD of length less than 300 m and / or pipe less than 323.9 mm O.D.*
steering / guidance tool	*specific tools providing steering direction information to the driller*

Appendix B Primary Regulatory and Information Contacts

Appendix B - Primary Regulatory and Information Contacts

Jurisdiction	Agency	Purpose
Federal	Fisheries and Oceans Canada (DFO) • District Manager or Impact Assessment Biologist	• In the event of drilling mud release in a watercourse. • Letter of advice or authorization. • Water withdrawal during drilling and testing.
	Transport Canada • Navigable Waters Protection Officer, Canadian Coast Guard	• Navigable water approval for temporary vehicle crossings or if an HDD fails and instream activities are planned.
	Indian and Northern Affairs Canada (INAC)	• Permission and approval of easement and HDD on Indian Reservations
	Indian Oil and Gas Canada (IOGC) • Environment and Surface Manager	• Permission and approval of easement and HDD on Indian Reservations
	Prairie Farm Rehabilitation Administration (PFRA) • Land Manager	• Permission and approval of easement and HDD on PFRA land.
	Other federal land authorities (*e.g.,* Department of Defense)	• Permission and approval of easement and HDD on federal Crown land.
Alberta	Alberta Sustainable Resource Development (ASRD) • Fisheries Biologist/Technician, Fish and Wildlife Division	• In the event of drilling mud release in a watercourse.
	Alberta Environment (AENV) • Regional Water Manager	• Notification under the *Code of Practice for Pipelines and Telecommunication Lines Crossing a Water Body* • In the event of drilling mud release in a watercourse
	ASRD • Public Lands and Forest Division	• Permission to access and construct HDD on provincial Crown land. • Water withdrawal approval/notification for drilling and testing.
	Alberta Energy and Utilities Board	• In the event of a drilling mud release • Provides regulations for disposal of drilling mud
British Columbia	BC Oil and Gas Commission Project Assessment Branch • Headquarters, Fort St. John	• Permission to access and construct HDD on patented and provincial Crown lands • Submit drilling waste management and clean-up form
	Land and Water British Columbia Inc. • Regional Offices	• Approval for short-term use of water or water license

Jurisdiction	Agency	Purpose
Manitoba	Manitoba Conservation • Director of Environmental Approvals, Environmental Approvals Branch	• Permission to access and construct HDD on patented and provincial Crown lands
New Brunswick	Department of Environment and Local Government • Watercourse Alteration Program Coordinator, Operational Support Branch	• Watercourse and Wetland Alteration Regulation permit
	Department of Natural Resource (DNR) • Wetlands and Coastal Habitat Program, Regional Offices	• letter of support for HDD near a coastal wetland
	Department of Natural Resources (DNR) • Land Use Application Service Centre, Crown Land Branch	• Authorization to access and construct HDD on provincial Crown land
Newfoundland and Labrador	Department of Environment • Water Resources Management Division	• Certificate of environmental approval
	Department of Government Services and Lands • Regional Office	• Permission to access and construct HDD on patented and provincial Crown land
Northwest Territories (not including Inuvialuit Settlement Region (ISR))	Mackenzie Valley Land and Water Board, Yellowknife • Executive Director	• Land use permit and water licence to construct HDD.
Northwest Territories (Inuvialuit Lands)	Inuvialuit Land Administration (ILA), Tuktoyaktuk • Land Administrator	• Permission to access and construct HDD on ISR patented lands • Reviews and approves applications to access and use Inuvialuit lands.
	Indian and Northern Affairs Canada (INAC), Yellowknife • Land Administration Officer	• Land use permits for Crown lands
	Northwest Territories Water Board, Yellowknife • NWT Water Board Office	• Water licences for Crown lands
	Environmental Impact and Screening Committee (EISC), Inuvik • Joint Secretariat	• Environmental screening of developments for impacts on Crown and occasionally patented land

Jurisdiction	Agency	Purpose
Northwest Territories (Gwich'in Lands)	Gwich'in Land Administration, Inuvik • Lands Manager	• Permission to access and construct HDD on Gwich'in patented lands
	Gwich'in Land and Water Board, Inuvik • Executive Director	• Water licence to construct HDD
Northwest Territories (Sahtu Lands)	Sahtu Land and Water Board, Fort Good Hope • Executive Director	• Water licence to construct HDD • Regulates the use of land and water by issuing, amending, renewing and suspending land use permits and water licences on all Crown, Sahtu lands and patented lands
Nova Scotia	Nova Scotia Department of Natural Resources • Director, Land Administration Division	• Permission to access and construct HDD on provincial Crown land. • Contact for HDD for coastal waters only
	Nova Scotia Department of Environment and Labour • Regional or District Office, Environmental Monitoring and Compliance Division	• Water licence for a watercourse alteration and for water allocation. • Contact for HDD for inland waters on patented and provincial Crown land.
Nunavut	Nunavut Planning Commission (NPC)	• Permission to access and construct HDD on private and Crown land. (Note: The NPC usually forwards copies of applications to NIRB, INAC, Nunavut Water Board and RIA, as well as any other agencies they determine may require a copy.)
	Nunavut Impact Review Board (NIRB)	• Environmental screening of developments for impacts on Crown and occasionally patented land
	Regional Inuit Association (RIA)	• Permission to access and construct HDD on Inuit-owned land
	INAC	• Permission to access and construct HDD on Crown land.
Ontario	Ontario Ministry of Environment • Environmental Assessment Branch • Approvals Branch	• Approval for water withdrawal. • Verbal notification 1 day before construction.
	Local or Regional Municipality	• Topsoil removal permit (not applicable if topsoil is held and replaced)
	Ontario Ministry of Natural Resources • District Office	• Permits to access and construct HDD on provincial Crown and patented lands. • Verbal notification 1 day before construction.
	Conservation Ontario • Conservation Authority	• Permit to construct HDD

Jurisdiction	Agency	Purpose
Prince Edward Island	Department of Environment and Energy • Environmental Impact Assessment Coordinator, Pollution Prevention Division	• Application for an Environmental Impact Assessment (EIA)
	Department of Environment and Energy • Watercourse/Wetland Alteration Supervisor, Conservation and Management Division	• Water alteration permit • Approval for water withdrawal
	Department of Environment and Energy • Chief Executive Officer, PEI Energy Corporation	• Notification of pipeline/HDD
Quebec	Ministere de l'Environment • Societe de la Faune et des Parcs du Quebec	• Application for Authorization: Projects in Aquatic Environments and on Shores; demande de certificat d"autoristion pour activities en milieux aqautique, humide et riverain
Saskatchewan	Saskatchewan Environment (SENV) • Oil and Gas Coordinator • Fish Ecologist/Technician	• Aquatic Habitat Protection Permit for patented and provincial Crown land
	Saskatchewan Watershed Authority (SWA) • Coordinator - Water Resource Administration	• Aquatic Habitat Protection Permit for patented and provincial Crown land
	Saskatchewan Agriculture and Food Rural Revitalization (SAFRR) • Regional Manager	• Permission to access and construct HDD on provincial Crown land.
	Saskatchewan Industry and Resources	• Drilling mud disposal requirements
Yukon	Department of Environment • Yukon Water Board • Water Resources Branch • Environmental Protection and Assessment Branch	• Water license approvals (Type "B" license to cross watercourses greater than 5 m wide) • Regulatory/ enforcement matters • Environmental assessments

Appendix C Example Drilling Execution Plan

Appendix C - Example Drilling Execution Plan

The contractor should develop and present to the owner a drilling execution plan that addresses the following items:

5) each step to be taken during mobilization, surface preparation, sump construction, anchor installation, casing installation, pilot hole drilling, hole opening operation, pullback operation and demobilization including a detailed drawing showing the intended drill path in plan and profile, depth of cover, entry angle, exit angle, depth and size of surface casings, and any other pertinent data;
6) drill rig specifications including push/pull force, torque and other specifications of the specific rig to be used on this project;
7) a full description of the drilling fluid recycling system, fluid flow operating rate, tanks, pumps, solids control/recycling, centrifuge(s) etc.;
8) proposed water supply for drilling;
9) drilling pipe description with certifications (size, grade and quantity);
10) details of drill rig anchoring system;
11) proposed steering system with limitations and access requirements;
12) pressure monitor type and pressure range, if required;
13) electronic drilling recorder type and functions monitored (if required);
14) sample of daily drilling reports; and
15) contingency plan to be employed in event of:
    a) casing removal difficulties;
    b) inadvertent returns to surface;
    c) equipment lost in the hole;
    d) hole collapse during pipe pull;
    e) pipe getting stuck during pull back;
    f) appearance of severe damage to the coating during pullback; and
    g) appearance of severe damage to the pipe during pullback.
16) a drilling fluid mitigation plan, including:
    a) a description of the proposed fluid type and additives complete with manufacturer's specifications (MSDS, etc.)
    b) written authorization from appropriate agencies to use additives, if required
    c) emergency response plan:
        i) notification procedures;
        ii) emergency containment and clean-up procedures plan for inadvertent fluid migration or release in a water body or on land (including inadvertent returns);.
        iii) emergency response equipment on site; and
        iv) a description of the fluid cleaning, recycling and control systems, including volumes of fluids and water tankage required;

d) disposal plan composed of:

   i) an estimate of the complete composition of the drilling waste including the relative quantities of water, bentonite, other sediments and drill cuttings, and any additives which may be necessary during construction or to allow flocculation prior to disposal;

   ii) method of containment and, if appropriate, disposal of drilling fluids onsite; and

   iii) off-site disposal plan (fluid disposal options);

      1. mix and bury onsite;
      2. haul to an approved dumpsite;
      3. land spreading; and
      4. written authorization from appropriate agencies to dispose of fluids

Appendix D HDD Related Conversions

Appendix D - HDD Related Conversions

MULTIPLY	BY	TO OBTAIN
Acre feet	43560	Cubic feet
Acre feet	1233.48	Cubic metres
Barrel	35	Imperial gallons
Barrel	42	U.S. gallons
Barrel	0.1193	Cubic metres
Cubic foot	0.0283	Cubic metres
Cubic foot	6.229	Imperial gallons
Cubic foot	7.481	U.S. gallons
Cubic metre	264.17	U.S. gallons
Cubic metre	35.3144	Cubic feet
Cubic metre	220.1	Imperial gallons
Cubic metre	6.289	Barrels
Cubic metre	1000	Litres
Cubic metre	2204.6	Pounds of water
Cubic metre	1000	Kilograms of water
Cubic foot/sec	0.02832	Cubic metres/sec
Foot	0.3048	Metres
Hectare	2.471	Acre
Kilogram	2.2046	Pounds
Kilograms/hectare	0.892	Pounds per acre
Kilopascals	0.145	Pounds per square inch
Metre	3.2808	Feet
Mile	1.609	Kilometres
Pound	0.45359	Kilograms
Pounds per square inch	6.895	Kilopascals
Pounds per acre	1.121	Kilograms/hectare

Appendix E Example (Alberta) - Pipeline Horizontal Directional Drilling

Appendix E - Example (Alberta) - Pipeline Horizontal Directional Drilling

E.1 Purpose

This plan provides guidance in the even of inadvertent returns of drilling fluid during an HDD.

E.2 General

Drilling mud is classified as an oilfield waste and is regulated under the jurisdiction of the Alberta Energy and Utilities Board (EUB). A *frac-out* or inadvertent release of drilling mud is considered *"Reportable"* to the applicable regulatory authorities when:

- the inadvertent release occurs in or close to sensitive aquatic or terrestrial receptors, or
- onto land and the release is in excess of 2 m^3 within the right-of-way, or
- any size of release outside the right-of-way that may cause, is causing or has caused an adverse effect.

Depending on the circumstances of the inadvertent release, the person responsible shall immediately report the release to the applicable authorities such as EUB, AENV, any affected landowners or public and, if into or near a water body, Fisheries and Oceans Canada (DFO).

To promote landowner or public understanding of drilling waste management, an information brochure entitled *EUB Guide 50-1; Landowner's Guide for Drilling Waste Disposal From Oil and Gas Wells* has been developed. Pipeline companies are expected to distribute this brochure to surface landowners and land occupants as part of the landowner approval process.

E.3 Recommended Inadvertent Response Plan

E.3.1 Inadvertent Release Response in Water

1. The HDD contractor is to stop the drilling operations immediately.

2. The HDD contractor or party designated to be responsible as determined in the contingency plan, is to contain the drilling mud and prevent further migration into the water body. In the case of an instream release, the downstream movement of drilling mud should be prevented if possible by isolating the release point or diverting higher velocities around the release.

3. The HDD contractor will immediately notify the owner or designate who will immediately contact the appropriate EUB Field Office and other applicable regulatory authorities. If a release into water has occurred or is

suspected to have occurred, the provincial fisheries biologist, Alberta Environment, DFO and Environment Canada should be notified.

EUB Field Service/Emergency (24 hours)	_____________
Regional Director	_____________
Provincial Fisheries Biologist	_____________
DFO Fisheries/Habitat Biologist	_____________
AENV Compliance Branch	(780) 422-4505
AENV Emergency Complaint Hotline (24 hours)	1-800-222-6514 or *7378 (Telus Mobile)

4. The drilling mud must be cleaned up immediately by the HDD contractor and/or drilling mud disposal contractor, if conditions allow, and disposed of as per EUB Guide 50 and EUB ID 99-05. If the potential exists for greater environmental impact due to the clean-up process than the presence of the drilling mud, regulatory agencies (*e.g.*, EUB, Alberta Environment, Alberta Sustainable Resource Development and DFO) should be notified if clean-up of drilling mud is not to be conducted immediately and the rationale for the delay should be provided. If the drilling mud has entered a water body or could enter a water body, a qualified aquatic environment specialist (QAES) should determine the appropriate actions to be taken and schedule of activities.

5. Drilling activities will not be resumed until a site-specific drill continuance plan and monitoring program have been approved by the owner. A third party drilling or geotechnical consultant may be needed to review and assess the drill continuance plan.

6. Prepare a report summarizing the events leading up to the release as well as measures taken following the release to minimize impacts on the environment. Submit the report to the Regional Director within 7 days.

E.3.2 Inadvertent Release Response on Land

1. The HDD contractor is to stop all operations immediately.

2. The HDD contractor or party designated to be responsible as determined in the contingency plan is to contain the drilling mud and prevent further migration using berms, sandbags or other appropriate structures or materials. Where appropriate, use vacuum truck or mud/trash pumps to recover fluids and drilling mud.

3. The HDD contractor will immediately notify the owner or designate who will determine if the release is reportable (see General section for definition of reportable inadvertent release) and, if reportable, contact the appropriate EUB Field Office and other applicable regulatory authorities.

4. The drilling mud must be cleaned up immediately by the HDD contractor and/or drilling mud disposal contractor if conditions allow, and disposed of as per EUB Guide 50.

   As noted above in point 4 of F.7.1, an assessment may be necessary if the potential exists for greater environmental impact due to the clean-up process than the presence of drilling mud. Involve applicable regulatory agencies in the discussion process.

5. Drilling activities will not be resumed until a site-specific drill continuance plan and a monitoring program have been approved by the owner. A third party drilling or geotechnical consultant may be needed to review and assess the drill continuance plan.

E.4 Drill Continuance Plan

Collectively the owner, HDD contractor and appropriate regulatory agency should determine the drill continuance plan. Depending on the situation being encountered and the potential impacts to the environment, specialists (*e.g.*, geotechnical engineers, QAES) may be needed to review and assess the plan. The drill continuance plan may include each of the following four strategies.

1. Fracture Plugging (Bridging) Agents

In certain types of formations or conditions, fracture plugging agents (non-toxic) have been utilized with limited success. These agents include ground pieces of carpet, ground corn husks, sawdust, bentonite pellets, walnut husks, sealant or other commercially available products. These are pumped down the drill hole and left undisturbed for a predetermined length of time where upon drilling is restarted. If positive circulation is restored, drilling is continued using the same principles and contingency plans; if not, drilling is halted.

2. Down Hole Cementing

If the fracture zone is determined to be too large for the use of plugging agents, the drill string may be inserted to a predetermine depth to allow a quick setting cement or thermal resin (non-toxic) to be pumped down-hole in sufficient quantities to seal off the problem zone. After setting up, the hole is redrilled through the sealed zone. If no further fracturing occurs, drilling is continued using the same principles and contingency plans; if not, drilling is halted.

3. Contain and Control

If the inadvertent release is on land, determined not to be causing an adverse effect and the surface migration of the drilling mud can be adequately contained and controlled, then drilling can continue with the following conditions:

- there are no impacts to the environment or other adverse effects. (*i.e.*, no potential to contaminate surface or groundwater, third party property damage or safety risks to the landowner, public or animals);
- the area affected by the inadvertent release is minor and limited to only one spot (affected area is less than 10 m^2);
- the surface migration of the drilling mud is adequately contained (bermed with subsoil or a catch pit excavated);
- the contained free drilling mud is adequately controlled (any free drilling mud migrating to the surface is immediately and continually removed for the duration of the remaining drilling phases);
- the site is monitored at appropriate periods during the drilling cycle and the drilling contractor reduces pump/hole pressure accordingly in order to maintain control of the amount of mud being contained (note that some release points may not need continuous monitoring since they are only prone to releases during a particular period in the drilling cycle);
- the affected landowner is notified and permission for continued drilling is granted;
- the plan is discussed with the appropriate EUB authority and other agencies (*e.g.*, DFO) and their approval is obtained; and
- the affected site is remediated and reclaimed to meet Alberta Environment's requirements for a contaminated site.

4. Partial Hole Recovery

In the event that both of the above procedures are unsuccessful, down-hole cementing could be used to seal off a substantial portion of the existing hole back to a point where a "kick-off" can take place. The drilling is then advanced along a different path usually at a lower elevation. Again, careful monitoring of drilling fluids and the drill path will be carried out using the same principles and contingency plans; if not, drilling is halted.

In the event that none of the above procedures are successful or considered feasible, the hole will be abandoned, and a re-drill will be considered at a second location if it can be determined that more favourable geotechnical conditions exist, using the same principles and contingency plans.

Pipeline Associated Watercourse Crossings 3rd Edition

October 2005

CAPP • CEPA • CGA

Fisheries and Oceans Canada | Pêches et Océans Canada
Oceans | Océans
Assistant Deputy Minister | Sous-ministre adjoint

Your file *Votre référence*

Our file *Notre référence*

September 12, 2005

Re. Pipeline Associated Watercourse Crossings, 3rd Edition

Fisheries and Oceans Canada (DFO) is pleased to endorse the above referenced manual and recognize it as a reference document for use both by industry and department employees in all regions. Under the guidelines of the Natural Resource Industry Associations (NRIA), DFO has worked with staff of the Canadian Association of Petroleum Producers (CAPP), the Canadian Energy Pipeline Association (CEPA) and the Canadian Gas Association (CGA) in the development of this edition.

Based on the recently developed DFO Risk Management Framework, this document is a compilation of modern planning considerations, "best practices" pipeline and vehicle watercourse crossing construction techniques, and available environmental protection methods to meet Provincial and Territorial regulatory requirements and minimize associated fisheries habitat impact.

DFO is committed to work with industry to regularly review this document and revise as appropriate, and ensure it is applied consistently by DFO Regions throughout Canada. This will ensure a streamlined and effective process for both DFO and the pipeline industry.

DFO looks forward to continuing to work co-operatively with the pipeline industry to ensure that fisheries habitat is adequately protected, while contributing to Canada's goal of Sustainable Development.

Sincerely,

Sue Kirby

Sue Kirby
Assistant Deputy Minister
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Ottawa, Canada
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Canada

The Canadian Association of Petroleum Producers (CAPP) is the voice of the upstream oil and natural gas industry in Canada. CAPP represents 150 member companies who explore for, develop and produce more than 98 per cent of Canada's natural gas, crude oil, oil sands and elemental sulphur.

Our members are part of a $75-billion-a year industry that affects the lives of every Canadian. Petroleum and the products made from it play a vital role in our daily lives. In addition to providing heating and transportation fuels, oil and natural gas are the main building blocks for an endless list of products - from clothing and carpets, to medicines, glues and paints.

Working closely with our members, governments, communities and stakeholders, CAPP analyzes key oil and gas issues and represents member interests nationally in 12 of Canada's 13 provinces and territories. We also strive to achieve consensus on industry codes of practice and operating guidelines that meet or exceed government standards.

The Canadian Energy Pipeline Association (CEPA) represents Canada's transmission pipeline companies. Our members are world leaders in providing safe, reliable long-distance transportation for over 95% of the oil and natural gas that is produced in Canada. CEPA is dedicated to ensuring a strong and viable transmission pipeline industry in Canada in a manner that emphasizes public safety and pipeline integrity, social and environmental stewardship, and cost competitiveness.

The Canadian Gas Association (CGA) is the voice of Canada’s natural gas delivery industry. CGA represents local distribution companies from coast to coast as well as long distance pipeline companies and related manufacturers and other service providers. CGA and its members stand at the junction where Canada’s gas delivery system meets the needs of over five million Canadian natural gas customers. CGA’s members deliver over 25% of the energy used in Canada.

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Overview

In 2004, the Canadian Association of Petroleum Producers (CAPP), Canadian Energy Pipeline Association (CEPA) and Canadian Gas Association (CGA) initiated revision of the Canadian Pipeline Water Crossing Committee (CPWCC) document *Watercourse Crossings, Second Edition* to incorporate regulatory and technological advancements. Feedback was solicited from government and industry regarding the second edition of *Watercourse Crossings*, and those comments were incorporated in this third edition.

This document outlines the present regulatory framework under which pipeline associated watercourse crossings are assessed and constructed in Canada. In addition, it suggests measures to assist pipeline companies, governing agencies and contractors during the planning, construction, operation and maintenance of pipeline associated watercourse crossings. The development of this document is seen as a means to promote a consistent approach to pipeline associated watercourse crossings throughout Canada and to aid in developing a common understanding among industry, government and other stakeholders.

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Glossary

Term	Definition
Anadromous	Fish species that travel up freshwater streams to spawn in fresh water, but spend a significant portion of its life in salt water.
Bank Full Width	The width of a watercourse when it completely fills its channel and the elevation of the water reaches the upper margins of the bank. In a natural channel that shows continuous evidence of scouring and sediment deposition, the bank full width is measured at the first break in slope at the top of the bank. In many cases this is delineated by the presence of permanent terrestrial vegetation such as large shrubs and trees.
Bed and Banks	The streambed and the rising slope or face of ground bordering a watercourse, up to the level of rooted terrestrial vegetation.
Compensation	The replacement of natural habitat, augmentation in the productivity of existing habitat or maintenance of fish production by artificial means, where mitigation measures are not adequate to maintain habitats for Canada's fisheries resources.
Corduroy	Nonsalvageable timber laid on the work side of the right-of-way during nonfrozen conditions to improve passage of traffic through wet areas or muskeg.
Cross Ditch	A shallow ditch cut into the surface of the right-of-way. Cross ditches run parallel to and are located on the upslope side of diversion berms.
Crossing Techniques	**Open Trenched/Open Cut**: The excavation of a trench in flowing water. Isolated: The crossing site is isolated from the main watercourse to prevent construction materials and sediment from entering the watercourse outside of the isolated area. **Dam/Pump**: A dam is placed in the stream channel to prevent the main flow of water from flowing through the area that will be subjected to disturbance within the stream channel. A pump is used to pump water from the upstream side of the excavation to the downstream side to bypass the instream construction area. **Flume**: A dam is placed in the stream channel to prevent the main flow of water from flowing through the area that will be subjected to disturbance within the stream channel. A large pipe (flume) is installed to permit the passage of water from the upstream side of the dam to the stream channel downstream of the work area. **Trenchless**: A crossing method in which there is no disturbance to the bed and banks of a waterbody. Trenchless crossing methods include horizontal bores, horizontal punches and directional drills.
Diversion Berm	An erosion control structure installed on slopes to divert surface water from the right-of-way.
Deleterious Substance	(a) Any substance that, if added to any water, would degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to the use by man of fish that frequent that water, or (b) Any water that contains a substance in such quantity or concentration, or that has been so treated, processed or changed, by heat or other means, from a natural state that it would, if added to any other water, degrade or alter or form part of a process of degradation or alteration of the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat or to the use by man of fish that frequent that water.
Deposit	Means any discharging, spraying, releasing, spilling, leaking, seeping, pouring, emitting, emptying, throwing, dumping or placing.
Fish	Includes: parts of fish; shellfish, crustaceans, marine animals and any parts of shellfish, crustaceans or marine animals; and, the eggs, sperm, spawn, larvae, spat and juvenile stages of fish, shellfish, crustaceans and marine animals.
Fish Habitat	Spawning grounds and nursery, rearing, food supply and migration areas on which fish depend directly or indirectly in order to carry out their life processes.

Term	Definition
Fishery	Includes the area, locality, place or station in or on which a pound, seine, net, weir or other fishing appliance is used, set, placed or located, and the area, tract or stretch of water in or from which fish may be taken by the said pound, seine, net, weir or other fishing appliance, and also the pound, seine, net, weir, or other fishing appliance used in connection therewith.
Frac-Out	The inadvertent seepage of drilling mud onto the ground or into surface waters through fractures in the subsurface. Frac-outs can occur when using pressurized crossing construction methods such as horizontal directional drilling.
Freshet	Rapid temporary rise in stream discharge and water level, caused by heavy rains or rapid melting of snow and ice.
Grubbing	A construction activity that involves removing vegetation, tree roots and stumps and surface soil from the pipeline right-of-way or other areas that will be under development.
HADD	Harmful alteration, disruption or destruction (HADD) of fish habitat is defined by Fisheries and Oceans Canada (DFO) as "any change in fish habitat that reduces its capacity to support one or more life processes of fish". It should be noted that this definition of HADD applies when determining if, or whether, any of the three conditions (*i.e.*, harmful alteration, disruption, or destruction) identified in Subsection 35(1) of the *Fisheries Act*, are likely to result from a project. These conditions do differ, and are differentiated essentially by the severity of impacts and their duration, as follows: harmful alteration - any change to fish habitat that indefinitely reduces its capacity to support one or more life processes of fish, but does not completely eliminate the habitat; disruption - any change to fish habitat occurring for a limited period which reduces its capacity to support one or more life processes of fish; and destruction - any permanent change of fish habitat which completely eliminates its capacity to support one or more life processes of fish.
Instream Activity	Usually interpreted as any activity conducted in a waterbody (*i.e.*, stream, river, lake, pond, isolated pool).
Mitigation	Actions taken during the planning, design, construction and operation of works and undertakings to alleviate potential adverse effects on the productive capacity of fish habitats.
Navigable Waterway	A navigable water is defined by the *Navigable Waters Protection Act* as being "any body of water capable, in its natural state, of being navigated by floating vessels of any description for the purpose of transportation, recreation or commerce, and may also be a man-made feature such as a canal or reservoir".
Net Gain	An increase in the productive capacity of habitats for selected fisheries brought about by determined government and public efforts to conserve, restore and develop habitats.
No Net Loss	A working principle by which DFO strives to balance unavoidable habitat losses with habitat replacement on a project-by-project basis so that further reductions to Canada's fisheries resources due to habitat loss or damage may be prevented.
Obstruction	Means any slide, dam or other obstruction impeding the free passage of fish.
Periphyton	Matrix of algae and microbes attached to submerged strata in aquatic ecosystems.
Productive Capacity	The maximum natural capability of habitats to produce healthy fish, safe for human consumption, or to support or produce aquatic organisms upon which fish depend.
Restoration (of Habitat)	The treatment or clean-up of fish habitat that has been altered, disrupted or degraded for the purpose of increasing its capability to sustain a productive fisheries resource.
Riparian	Pertaining to anything connected with, or immediately adjacent to, the banks of a watercourse or waterbody.
Riprap	A foundation or revetment made of irregularly placed stones or pieces of boulder on earth surfaces (*e.g.* stream banks) to reduce erosion of underlying soil or material by water.

Term	Definition
Shoo-Fly	Temporary access road generally used near watercourse crossings with steep valley slopes, to allow vehicles to traverse the slopes on a gentler grade.
Subdrain	Subsurface drain that is installed at trench depth, or slightly deeper, that is designed to move groundwater away from the trench line and drain the water off the right-of-way.
Thalweg	A line parallel to the direction of flow that defines the deepest and fastest portion of a stream channel.
Total Suspended Solids (TSS)	A measure of the total concentration of suspended solids, (*i.e.* material such as silt, clay, organic matter and microscopic organisms) that is suspended or carried in the water column and not in contact with the bottom substrate in water.
Trench Breaker	An erosion control device consisting of impermeable material that is placed within the trench after the pipe has been lowered in and before backfilling. Trench breakers are designed to block the water movement along the trench line and direct it to the surface where it is directed away from the trench line.
Trench Plug	A small portion of the ditch line that is left unexcavated, to block water flow along the trench or allow wildlife to cross the trench at known and used wildlife trails.

List of Acronyms

Acronym	Definition
AENV	Alberta Environment
ASRD	Alberta Sustainable Resource Development
C&R	Conservation and Reclamation
CAPP	Canadian Association of Petroleum Producers
CCME	Canadian Council of Ministers of the Environment
CEAA	*Canadian Environmental Assessment Act*
CEPA	Canadian Energy Pipeline Association
CGA	Canadian Gas Association
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
CPWCC	Canadian Pipeline Water Crossing Committee
DAP	Development Assessment Process (Yukon)
DFO	Fisheries and Oceans Canada
GPR	ground penetrating radar
HADD	harmful alteration, disruption or destruction [of fish habitat]
HDD	horizontal directional drill
ILA	Inuvialuit Land Administration
INAC	Indian and Northern Affairs Canada
IOL	Inuit owned lands
ISR	Inuvialuit Settlement Region
MFO	Minister of Fisheries and Oceans (Federal)
MOE	British Columbia Ministry of Environment
MVLWB	Mackenzie Valley Land and Water Board
MWLAP	British Columbia Ministry of Water, Land and Air Protection
NEB	National Energy Board
NIRB	Nunavut Impact Review Board
NLCA	Nunavut Land Claims Agreement
NSA	Nunavut Settlement Area
NTU	nephelometric turbidity units
NWB	Nunavut Water Board
NWT	Northwest Territories
NWPA	*Navigable Waters Protection Act*
NWPP	Navigable Waters Protection Program
OMNR	Ontario Ministry of Natural Resources
OS	operational statement
PEI	Prince Edward Island
PLA	pipeline agreement
POE	pathway of effect
RMF	risk management framework
TC	Transport Canada
TSS	total suspended solids
YESAA	*Yukon Environmental and Socioeconomic Assessment Act*

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1 Introduction

Watercourse crossings are a unique component of pipeline construction projects. Watercourse crossing construction typically requires devoted crews and specialized equipment, specific engineering design and specific planning and regulatory approval considerations. Crossings pose unique risks to the success of pipeline projects, and ultimately to the contractors that construct them.

The regulatory requirements for the approval and construction of pipeline associated watercourse crossings in Canada vary according to the jurisdiction in which the project is being built and the environmental setting within which the project is planned. The Canadian Association of Petroleum Producers (CAPP), formerly the Canadian Petroleum Association, the Canadian Energy Pipeline Association (CEPA) and various committees have been tracking this issue for over twenty-five years. To ensure that regulators, industry and other stakeholders are kept current on new initiatives from a regulatory and technical standpoint, CAPP, CEPA and the Canadian Gas Association (CGA) have updated the Second Edition, *Watercourse Crossings* (1999) with this Third Edition of *Pipeline Associated Watercourse Crossings*.

This document is intended to give regulators, industry practitioners and other stakeholders a summary of aspects of planning and constructing pipeline associated watercourse crossings. Its development is seen as a means to promote a consistent approach to pipeline associated watercourse crossings throughout Canada and to aid in developing a common understanding among industry, regulators and others (*e.g.*, nongovernment organizations). *Pipeline Associated Watercourse Crossings* strives to offer the reader options for consideration in the planning, review, approval and construction, as well as operations and maintenance, of pipeline associated watercourse crossings.

This document does not address any aspect of water withdrawal or discharge associated with hydrostatic testing. CAPP/CEPA have prepared a separate document on the regulatory and environmental requirements for hydrostatic testing in Canada (CAPP 1996a).

1.1 Updates to Document

This edition concentrates on recent regulatory and technical advances in pipeline associated watercourse crossings. Much of the information is repeated from CAPP (1993) and the Canadian Pipeline Water Crossing Committee (CPWCC) (CPWCC 1999), but has been updated with information from a consultation program involving key regulators from all jurisdictions as well as industry representatives. The consultation program attempted to clarify objectives and information requirements from each jurisdiction, as well as tap the field expertise of industry representatives and regulatory agents as to their observations and recommendations regarding pipeline associated watercourse crossing construction.

This Third Edition of *Pipeline Associated Watercourse Crossings* has been revised to incorporate Fisheries and Oceans Canada's (DFO) *Risk Management Framework for Development Projects Impacting Fish Habitat* and the Pathways of Effects (POE) models. As a component of their efforts to streamline the application and approval process for common development projects, DFO has provided detailed comments of the technical aspects of this manual. Commentary on risk management during crossing selection and construction and cumulative environmental effects has also been added to this edition.

Comments on the Second Edition of this document were solicited from a variety of regulatory and industry sources in late 2004 and incorporated into the revisions. A draft of the Third Edition was circulated to those who responded with comments and again their input was incorporated into the document. This final version has since been reviewed by many practitioners active in the planning, construction and inspection of pipeline associated watercourse crossings, and takes into account their many years of collective experience.

1.2 Effects on Aquatic Habitat

Stream channel morphology is influenced by gradient (topography), basin catchment area, surficial and bedrock geology, channel substrate, amount of precipitation (average and extremes) and human and animal activity (beaver and man-made dams or other impoundments). The distance that suspended and bedload sediment is transported along a watercourse is a function of particle size, water velocity and channel configuration. The smaller the particle size and steeper the gradient, the further it travels. Two classes of particles can affect fish habitat adversely: Silt and clay (diameter <62 microns) are readily suspended and travel farther than sand and coarser particles (diameter >62 microns), which are more likely to settle within a short distance of the crossing. Typically, it is the deposition of particles from the water column and the movement of bedload that can compromise aquatic habitat suitability for resident fish.

Elevated total suspended solids (TSS) and accelerated bedload movement can affect water quality, as well as alter channel morphology and streambed composition (Anderson *et al.* 1996). With traditionally trenched crossings, altered channel cross-sectional characteristics can arise following excavation and backfilling. In addition, particles carried by water are abrasive and their movement can physically erode channels (Anderson *et al.* 1996). If TSS levels remain elevated for a prolonged duration (days or weeks) during certain periods of the year, primary productivity of a watercourse can be inhibited downstream of the crossing.

Depending on the amount and type of substrate affected, and the duration of the effect, bedload movement can reduce substrate porosity, pool depth and riffle area. All three aspects can have negative consequences for fauna living downstream of the crossing. Reduced depth compromises a pool's ability to overwinter fish and can render it less suitable as a rearing and foraging habitat for juveniles and summer feeding and holding habitat for adults. Reduced riffle area results in a loss of oxygenated habitat suitable for benthic invertebrates, reduced diversity of benthic invertebrate communities downstream of the crossing, indirect loss of preferred prey for fish within the affected area, loss of spawning areas, loss of interstitial habitat for invertebrates and loss of interstitial nursery and rearing habitat for eggs and young fish.

Interruption or disruption of surface flows during open trenched watercourse crossings can produce areas immediately downstream that are dewatered and/or shallower than before the onset of the crossing. Habitat loss and/or mortality of fish and benthic invertebrates can occur due to stranding or reduced flow volumes. If suitable mitigation measures are not implemented, the timing, degree and duration of the disruption in streamflow dictates the consequences to aquatic resources downstream.

1.2.1 Effects on Fish Populations

In general, fish populations that inhabit coldwater watercourses are more sensitive to changes in TSS than those resident in cool or warm water habitats (Scott and Crossman 1973). Generally, fish populations that inhabit larger, slower flowing watercourses at lower elevations have evolved to tolerate higher suspended sediment concentrations. Since larger watercourses typically remain turbid for longer periods of time, resident fish such as burbot, walleye, sauger, goldeye and sucker have adapted accordingly (Anderson *et al.* 1996).

Elevated TSS can affect fish individually through altered behaviour and/or physiology or, more generally, at the population level. Behavioural and physiological responses in fish are linked. In general, fish exposed to elevated levels of suspended sediment for extended periods experience biological (population) and physical (individual) stress. The degree of response is species and life-history stage specific (*i.e.*, egg, fry, juvenile, adult), and dictated by the magnitude and duration of exposure to the sediment plume.

Behavioural responses experienced by fish exposed to elevated TSS include suspension of territorial behaviour, depressed feeding rate and stimulated cough reflex. On experiencing discomfort, fish will move out of a sediment plume to ease the physical discomfort associated with gill abrasion if possible. Reduced feeding rate occurs in response to decreased instream visibility associated with elevated turbidity, TSS and stress in addition to reduced food supply. Increases in territoriality associated with movement out of the channel elevates biological stress both at the individual and population level as fish compete for less turbid territories, or establish new ones elsewhere within the system.

Physiological effects in fish exposed to elevated TSS are associated with stress, which can weaken an organism's immune system. Over extended periods, depressed feeding rates can be manifested in lower growth rate. Damaged gill filaments impair respiration, lead to elevated stress, changes in blood chemistry, decline in overall fish health, reduced immune system function, increased vulnerability of an individual/population to disease and parasitism and, in the long term, reduced survival. Severe stress can lead to mortality once fish health is compromised.

Elevated sediment concentrations can affect fish further downstream of the crossing location at the population level through increased egg mortality, decreased hatching success and loss of suitable spawning substrate. Like eggs, fish larvae have limited mobility and cannot avoid sedimentation of substrate or elevated TSS. Failed recruitment from eggs to larvae to juveniles ultimately affects annual production of a population within a watercourse. Similarly, loss of suitable spawning habitat as a consequence of sedimentation can adversely affect fish populations that rely on clean substrate for spawning and juvenile rearing.

1.2.2 Additional Consequences of Watercourse Crossings

Loss of riparian vegetation associated with clearing and/or grading of the banks to access a watercourse crossing can affect all life-history stages of fish. Clearing of riparian areas can locally raise water temperature within adjacent nearshore shallow areas reducing their attractiveness as incubation, rearing, foraging and escape habitat for selected species. Loss of instream and overhead cover as a result of right-of-way construction can reduce the habitat quality for resident fish populations. Cleared rights-of-way can become persistent sources of sediment to a watercourse if they are not suitably reclaimed. Introduction of sediment and increased water temperature can compromise water quality and the integrity of downstream aquatic habitat.

Crossings can create movement barriers that reduce fish distribution and abundance. It is common for contractors to place excessive amounts of riprap over a pipeline, which can obstruct fish movement during periods of low flow. Furthermore, clearing and grading of rights-of-way at watercourse crossings can increase fish mortality indirectly, since improved access for anglers can expose previously remote sections of a watercourse to harvest.

The use of explosives can result in harm to fish habitat and/or mortality or injury of resident fish and invertebrates through damage to internal organs and crushing, as a consequence of the pressure wave associated with blasting. Mortality is influenced by factors such as water depth (*i.e.*, in shallow water much of the blast energy is released above the water), as well as the type and amount of explosive detonated, but tends to be limited to the immediate vicinity of the crossing. In addition, an accidental release of hazardous materials (*e.g.*, hydraulic fluid) from equipment or a fuel spill into a watercourse or within the riparian right-of-way, can lead to stress or fish kills at and downstream of the crossing.

Disruption of instream groundwater upwelling through sedimentation or disturbance to groundwater flows can adversely affect spawning habitat for salmonids and overwintering habitat.

The transfer of aquatic organisms between watersheds by dirty equipment or test water can lead to the introduction of weeds such as purple loosestrife and Eurasian milfoil as well as aquatic diseases, parasites or other pests such as whirling disease, zebra mussels or exotic species not previously found in the watershed.

1.2.3 Natural Watercourse Dynamics

Natural storm and flood events can destabilize streambanks, create landslides within riparian zones and alter flow regimes within watercourses. It is the intensity and frequency of these events that ultimately influence channel morphology and the abundance, distribution and composition of resident fish and fish habitat. Natural flushing and stabilization of the system after an event permits recolonization and settlement of fish and benthic invertebrate populations within affected reaches. Watercourses are inherently dynamic and their fish populations have adapted to cope with natural catastrophic events. Landslides and floods both can contribute large quantities of sediment, however, both typically occur when flows are high and dilution of sediment levels facilitates their tolerance by fish populations and transport downstream.

The cumulative effects of human activities within watercourses and riparian areas can magnify the outcome of a storm or flood event and prolonged, unnatural events can stress fish populations. Consequently, when designing pipeline crossings of watercourses, it is important to acknowledge the degree of existing development in the area in conjunction with fish presence, distribution and habitat suitability for spawning, incubating, rearing, foraging, resting and overwintering at and immediately downstream of a proposed crossing.

1.3 Objectives for Watercourse Crossings

The overall goals and objectives of regulatory agencies for pipeline associated watercourse crossings are similar across Canada. However, there may be substantial variation in the construction techniques allowed as well as environmental protection and mitigation measures that are required for project approval among the various jurisdictions. The main guiding principle for all agencies across Canada, however, parallels the DFO guiding principle of "no net loss" of productive capacity of fish habitat.

In addition, and consistent with DFO's guiding principle, the following goals and objectives have been identified by regional regulatory personnel to prevent or mitigate harmful alteration, disruption or destruction (HADD) on fish and fish habitat at watercourse crossings:

- minimize duration of time spent working instream;
- use the most practical construction method resulting in the least adverse effect;
- abide by instream timing restrictions (*i.e.*, avoid seasonal high risk periods within lifecycles of resident aquatic organisms);

- maintain clean water flow and eliminate where possible the release of sediment or suspended solids;
- minimize disturbance of the watercourse bed and banks;
- minimize erosion of the watercourse bed and banks;
- use sediment control measures where warranted;
- maintain downstream flow;
- restore riparian areas and crossing approaches to prevent or minimize the release of sediments into watercourses;
- maintain fish passage during instream construction activities;
- ensure that no deleterious materials (*e.g.,* sediment, fuel) are deposited into any watercourse;
- minimize cumulative effects of construction activities on the surrounding environment;
- fully mitigate all adverse effects of construction in a watercourse to minimize temporary and permanent fish habitat loss;
- restore hydraulic, hydrologic or hydrogeological characteristics of the watercourse to their original condition; and
- ensure habitat compensation is implemented where harmful effects cannot be avoided or mitigated.

Ideally, proponents should use this list to develop corporate watercourse crossing objectives or to develop site-specific objectives for individual crossings or projects. Explicit watercourse crossing directives have the following benefits:

- facilitate consistent selection of appropriate crossing method;
- facilitate selection of most appropriate crossing locations;
- provide guidance to staff, contractors and regulators for approval, construction and monitoring;
- provide standard performance measures;
- allow proponents and contractors to evaluate crossing success;
- help proponents identify key risk areas and activities; and
- help proponents identify areas where cost or risk can be minimized with no adverse biophysical effects.

2 Regulatory and Information Requirements

The regulatory requirements for the construction, operation and abandonment of pipeline associated watercourse crossings in Canada vary according to the jurisdiction in which a project is being built. Each watercourse crossing may be subject to federal, provincial and territorial review. Many jurisdictional agencies have Codes of Practice, guidelines and policies regarding watercourse crossings, and require application for permits, authorizations and licenses.

Sections 2.1 and 2.2 describe the federal, provincial and territorial regulatory framework. Information requirements for each of these agencies are briefly discussed. This document has been written to reflect the regulatory information requirements at the time of publication. It does not address draft or proposed acts, Codes of Practice, guidelines or policies.

Table 2.1 provides a quick summary checklist of the regulatory framework and the appropriate contacts. Since the regulatory requirements are complex and continually changing across the country, the responsibility to ensure that all requirements are met falls on the proponent. Project planners should confirm with the appropriate agencies that the necessary permit applications are made and the regulatory requirements have been identified. Proponents should consult with regulatory authorities early in the planning process to ensure they understand the regulatory requirements.

2.1 Federal Jurisdictions

There are eight federal acts that are most applicable to pipeline associated watercourse crossings in Canada:

- *Fisheries Act;*
- *Navigable Waters Protection Act;*
- *National Energy Board Act;*
- *Canadian Environmental Assessment Act;*
- *Indian Oil and Gas Act*;
- *Canada Oil and Gas Operations Act;*
- *Species At Risk Act;* and
- *Migratory Birds Convention Act.*

Table 2.1 Regulatory and Information Contacts

Jurisdiction	Legislation	Contact
Federal	*Fisheries Act*	• Fisheries and Oceans Canada, Habitat Management Program, Regional Office
	Navigable Waters Protection Act	• Transport Canada, Navigable Waters Protection Program Regional Office
	National Energy Board Act	• National Energy Board
	Canadian Environmental Assessment Act	• Canadian Environmental Assessment Agency • Responsible Federal Authority (*e.g.,* Fisheries and Oceans Canada, National Energy Board)
	Indian Oil and Gas Act	• Indian and Oil Gas Canada
	Canada Oil and Gas Operations Act	• National Energy Board
	Species At Risk Act	• Environment Canada, Canadian Wildlife Service
	Migratory Birds Convention Act	• Environment Canada, Canadian Wildlife Service
Alberta	*Environmental Protection and Enhancement Act*	• Alberta Environment, Regulatory Approvals Centre, Enforcement and Monitoring Manager, Regional Office • Alberta Sustainable Resource Development, Fish and Wildlife, Regional and District Offices
	Public Lands Act	• Alberta Sustainable Resource Development, Public Lands and Forest, Regional Office
	Water Act	• Alberta Environment, Water Management, Regional Office
British Columbia	*Environmental Assessment Act*	• British Columbia Ministry of Environment, Environmental Protection Division, Regional Operations
	Fish Protection Act	• British Columbia Ministry of Environment, Environmental Stewardship Division, Regional Operations • Land and Water British Columbia Inc., Water Management Branch, Regional Office
	Forest Practices Code of British Columbia Act	• British Columbia Ministry of Forests, Regional Office
	Land Act	• Land and Water British Columbia Inc., Regional Office
	Oil and Gas Commission Act	• British Columbia Oil and Gas Commission, Regional Office
	Water Act	• Land and Water British Columbia Inc., Water Management Branch, Regional Office
Manitoba	*Crown Lands Act*	• Manitoba Conservation, Lands Branch
	Environment Act	• Manitoba Conservation, Environmental Stewardship Division, Environmental Approvals Branch
	Water Resources Administration Act	• Manitoba Water Stewardship - Water Licensing Branch
	Water Rights Act	• Manitoba Water Stewardship - Water Licensing Branch

Table 2.2 Regulatory and Information Contacts, Cont'd

Jurisdiction	Legislation	Contact
New Brunswick	*Clean Environment Act*	• New Brunswick Department of Environment and Local Government, Project Assessment Branch
	Clean Water Act	• New Brunswick Department of Environment and Local Government, Regional Services Branch, Water and Wetland Alteration Program
	Crown Lands and Forest Act	• New Brunswick Department of Natural Resources, Regional Office
	Fish and Wildlife Act	• New Brunswick Department of Natural Resources, Regional Office
	Quarriable Substances Act	• New Brunswick Department of Natural Resources, Regional Office
Newfoundland and Labrador	*Water Resources Act*	• Newfoundland and Labrador Department of Environment and Conservation, Water Resources Management Division
	Environmental Protection Act	• Newfoundland and Labrador Department of Environment and Conservation, Environmental Assessment Division
Northwest Territories *(Unsettled claims areas and transboundary projects)*	*Mackenzie Valley Resource Management Act*	• Mackenzie Valley Land and Water Board
Northwest Territories *(Inuvialuit Lands)*	*Inuvialuit Final Agreement*	• Inuvialuit Land Administration
	Territorial Lands Act	• Indian and Northern Affairs Canada • Land Titles Office
	Northwest Territories Waters Act	• Northwest Territories Water Board
Northwest Territories *(Gwich'in Lands)*	*Gwich'in Final Agreement*	• Gwich'in Tribal Council
	Mackenzie Valley Resource Management Act	• Gwich'in Land and Water Board
Northwest Territories *(Sahtu Lands)*	*Sahtu Dene and Metis Comprehensive Land Claim Agreement*	• Sahtu Land Development Corporation
	Mackenzie Valley Resource Management Act	• Sahtu Land and Water Board
Nova Scotia	*Crown Lands Act*	• Nova Scotia Department of Natural Resources, Land Administration Division
	Environment Act	• Nova Scotia Department of Environment and Labour, Environmental Assessment Branch, Water and Waste Water Branch
Nunavut	*Nunavut Land Claim Agreement*	• Nunavut Planning Commission, Regional Planning Office • Nunavut Impact Review Board
	Territorial Lands Act	• Indian and Northern Affairs Canada, Land Administration Unit
	Nunavut Waters and Nunavut Surface Rights Tribunals Act	• Nunavut Water Board

Table 2.2 Regulatory and Information Contacts, Cont'd

Jurisdiction	Legislation	Contact
Ontario	*Conservation Authorities Act*	• Ontario Conservation Authority • Local Authority
	Environmental Assessment Act	• Ontario Ministry of Environment, Environmental Assessment Branch
	Environmental Protection Act	• Ontario Ministry of Environment
	Lakes and Rivers Improvement Act	• Ontario Ministry of Natural Resources, Regional Office
	Public Lands Act	• Ontario Ministry of Natural Resources
	Ontario Water Resources Act	• Ontario Ministry of Natural Resources Approvals Branch
Prince Edward Island	*Environmental Protection Act*	• Prince Edward Island Department of Environment, Energy and Forestry
Québec	*Conservation and Development of Wildlife Act (Loi sur la conservation et la mise en valeur de la faune)*	• Société de la faune et des parcs du Québec, Direction de la faune et des habitats
	Environmental Quality Act (Loi sur la qualité de l'environnement)	• Ministère de l'environnement, Direction des politiques du secteur municipal
Saskatchewan	*Environmental Assessment Act*	• Saskatchewan Environment, Regional Office
	Environmental Management and Protection Act	• Saskatchewan Environment, Regional Office
Yukon	*Yukon Environmental and Socioeconomic Assessment Act*	• Yukon Government Executive Council Office, DAP Branch • *Yukon Environmental and Socioeconomic Assessment Act* Board
	Territorial Lands (Yukon) Act	• Yukon Department of Energy, Mines and Resources
	Waters Act	• Yukon Water Board

2.1.1 *Fisheries Act*

The *Fisheries Act* was enacted to protect fish, fish habitat and water frequented by fish and to provide for sustainable fisheries in Canada. Responsibility for the *Fisheries Act* rests with the Minister of Fisheries and Oceans (MFO). Fisheries and Oceans Canada (DFO) administers the habitat protection provisions (Section 35) of the *Fisheries Act*, while Environment Canada, under a 1985 Memorandum of Understanding with DFO, administers those provisions of the *Fisheries Act* dealing with the control of pollution (Section 36).

There are nine sections in the *Fisheries Act* (paraphrased below) most likely to pertain to pipeline associated watercourse crossings:

- Section 20 Provides for safe passage of fish.

- Section 22 Provides for flow of water and passage of fish.
- Section 30 Provides for water diversions or intakes to have a fish guard or screen.
- Section 32 Prohibits the destruction of fish by any means other than fishing except as authorized by the MFO or regulation.
- Subsection 35(1) Prohibits works or undertakings that result in harmful alteration, disruption or destruction (HADD) of fish habitat.
- Subsection 35(2) Allows for the authorization of HADD by the MFO.
- Subsection 36(3) Prohibits the deposition of deleterious substances in waters frequented by fish.[1]
- Subsection 37(1) Where HADD of fish habitat or a deposit of deleterious substance results or is likely to result from an existing or proposed work or undertaking, the MFO may request plans and specifications to be submitted for review.
- Subsection 37(2) Where the Minister is of the opinion that contravention of ss.35(1) or ss.36(3) is being or is likely to be committed, the MFO may order modification, restrict or close an undertaking subject to Governor in Council approval.
- Subsection 38(6) Allows for enforcement of inspector's orders.

Additional Sections of the *Fisheries Act* (*e.g.*, Sections 2, 34) provide definitions, such as those summarized in the Glossary. Other Sections (*e.g.*, Sections 40, 42, 78, 79) describe matters such as fines, offences and penalties.

Failure to comply with the habitat protection or pollution prevention provisions of the *Fisheries Act* may result in charges being laid. A court, upon conviction for offences under these provisions, may impose fines and court orders. For example, upon conviction of an indictable offence, a person found guilty of contravening Subsection 35(1) is liable to a fine not exceeding 1 million dollars for a first offence.

DFO has developed tools to promote the protection of fish and fish habitat, the foremost of which is the *Policy for the Management of Fish Habitat* (DFO 1986). Additional guidance and advice is provided in the following documents:

- *Fish Habitat Conservation and Protection: Guidelines for Attaining No Net Loss* (DFO 1995a).
- Fish Habitat Conservation and Protection: *"What the Law Requires - The Directive on the Issuance of Subsection 35(2) Authorizations*: (DFO 1995b).
- *Freshwater Intake End-of-Pipe Fish Screen Guideline* (DFO 1995c).
- *Decision Framework for the Determination and Authorization of Harmful Alteration, Disruption or Destruction of Fish Habitat* (DFO 1998).
- *Habitat Conservation and Protection Guidelines* (DFO 1999).

[1] Enforced by Environment Canada.

In addition, some DFO regional offices have developed specific documents for proposed works or undertakings in a particular geographic area. For example, DFO information requirements for watercourse crossings in Ontario are outlined in the document *Fisheries-Related Information Requirements for Pipeline Water Crossings* (Goodchild and Metikosh 1994) and DFO Prairies Area has published an operational position statement for pipeline crossings that outlines notification and approval requirements (DFO 2005).

In its review of project proposals, DFO applies the guiding principle of "no net loss" of the productive capacity of fish habitat. Under this principle, DFO strives to balance unavoidable habitat loss with habitat replacement on a project-by-project basis. A more detailed discussion of Habitat Compensation appears in Section 6.0 of this document.

Section 35 of the *Fisheries Act* prohibits the HADD of fish habitat except where authorized by the MFO. Documents noted above, such as *What the Law Requires - The Directive on the Issuance of Subsection 35(2) Authorizations* provide additional guidance to proponents. Section 58 and Schedule VI of the Fishery (General) Regulations provide the forms that applicants for Subsection 35(2) Authorizations may use.

Where proponents are planning a watercourse crossing that has a high risk of HADD, they must contact DFO to discuss the project. It should be noted that DFO has developed working relationships with a number of other agencies and initial contact may differ throughout the country (see Section 2.2 of this report). Proponents are advised to familiarize themselves with local working relationships between DFO and other agencies. If after reviewing the information the regulatory decision is that HADD is not likely to result or can be mitigated, a letter of advice may be provided to the proponent that outlines the measures required to avoid HADD. Should the proponent not implement the measures or change the project and HADD occurs, charges under the *Fisheries Act* could be brought against the proponent.

In cases where it is not possible to protect fish habitat by mitigation or project design, a Subsection 35(2) Authorization may be issued. In accordance with DFO’s policy, an Authorization will stipulate the conditions necessary to achieve "no net loss" of productive capacity of fish habitat (*i.e.*, compensation measures). Authorizations may not be issued in all cases.

Section 32 of the *Fisheries Act* prohibits the destruction of fish by means other than fishing except as where authorized by DFO and may apply in those situations where a proponent is planning the use of explosives for a watercourse crossing. Additional details regarding the use of explosives in watercourses are provided in sections 5.2.7 and 7.1.5 of this report.

2.1.2 Navigable Waters Protection Act

The *Navigable Waters Protection Act* (*NWPA*) provides a legislative mechanism for the protection of the public right of marine navigation on all navigable waterways in Canada. This is accomplished through permitting of the construction of works built or placed in, over, through or across navigable waterways and through a legal framework to deal with obstacles and obstructions to navigation. The *NWPA* is administered by the Navigable Waters Protection Program (NWPP) of Transport Canada (TC).

A navigable waterway is defined as being any body of water capable of being navigated by floating vessels of any description for the purpose of transportation, commerce or recreation. This includes both inland and coastal waters. The authority to determine the navigability of a waterway rests with the Minister of Transport or his/her designated representative.

The pertinent sections of the *NWPA* for pipeline associated watercourse crossings are found in:

- Paragraph 5(1)(a) — No work shall be built or placed in, on, over, under, through or across any navigable water unless the work, the site and plans thereof have been approved by the Minister, on such terms and conditions as the Minister deems fit, prior to commencement of construction.
- Subsection 5(2) — Except in the case of a bridge, boom, dam or causeway, paragraph 5(1)(a) does not apply to any work that in the opinion of the Minister does not interfere substantially with navigation.

Pipelines that cross navigable waters solely within the boundaries of one province or territory require either determination or approval under the *NWPA*. Application guidelines have been prepared by TC (2004). Projects are normally processed under Subsection 5(2) of the *NWPA* and a Subsection 5(2) determination is issued if the project does not interfere substantially with navigation. Proponents must submit a letter of application and plan information to the Regional NWPP Office of TC and notify the NWPP inspector when construction is finished so that a final inspection may be done to verify that all plans and recommendations were followed.

Projects in which construction has the potential to substantially interfere with navigation are dealt with under Subsection 5(1) and require a more formal Approval Process. Initial submissions for this approval include a letter of application, site and construction drawings, authorization by owner and environmental assessment documentation.

In addition to TC approval, watercourse crossings of an international or interprovincial pipeline are subject to review under the *National Energy Board (NEB) Act*. More details regarding this approval are provided in Section 2.1.3.

2.1.3 National Energy Board Act

The *National Energy Board Act* is an independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries. The NEB's purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. Under the *NEB Act*, the NEB has assumed a mandate for environmental protection as a component of the public interest. The NEB also has responsibilities under the *CEAA* to ensure that projects receive appropriate levels of assessment before proceeding. The NEB's environmental responsibility includes ensuring that the environment is protected during planning, construction, operation and abandonment of energy projects within its jurisdiction.

The NEB regulates:

- interprovincial and international pipelines
- pipeline transportation, tolls and tariffs
- international and designated Interprovincial power lines
- exports of oil, natural gas and electricity
- frontier oil and gas activities (*Canada Oil and Gas Operations Act*) outside of Accord areas

The NEB also regulates activities on or adjacent to rights-of-way under NEB jurisdiction in the interests of protection of property and the environment as well as the safety of the public and of the pipeline company's employees.

Before a company can do any pipeline construction work on a NEB-regulated project, it must apply for, and receive approval for the project from the NEB before it can build a pipeline, make changes to it, sell it or abandon it. To submit an application, the company must follow the *NEB Act*, the NEB *Rules of Practice and Procedure* (Government of Canada 1995) and the NEB *Filing Manual* (NEB 2004) and other legislation and regulations such as the *CEAA* that may be relevant. Companies preparing an application are required to anticipate the environmental issues and concerns created by the proposed project and to consult with appropriate government bodies, public interest groups, aboriginal persons and affected landowners.

Once the application has been submitted and filed, the NEB becomes directly involved with the project as the application is now a formal request for approval. The application will describe:

- the purpose of the pipeline;
- the pipeline design;
- environmental impacts of the project;
- if any public consultations have been held;
- any land rights needed;

- the adequacy of supply and the market potential for the products it will carry;
- the economics of the pipeline;
- the proposed route corridor; and
- any other factors that may affect the NEB's decision.

It is the responsibility of the NEB to consider all aspects of the project in order to determine if the pipeline project is in the public interest.

The *CEAA* process is initiated when a company provides a preliminary submission or submits an application to the NEB that triggers the *CEAA* and the NEB determines that it is a Responsible Authority (RA). The NEB considers the level of environmental assessment required under the *CEAA* (*i.e.*, screening, comprehensive study or panel review) and identified other possible RAs and Federal Authorities (FAs) who may have an interest in the project. The *CEAA* assessment is conducted within the NEB Act process, which is subject of the rules of natural justice. Any CEAA determination is made prior to the NEB taking any regulatory decision under the *NEB Act*.

Public hearings may be conducted orally or through written correspondence and documents only. Both processes allow for public participation. The public hearing gives all of the people concerned with a project an opportunity to express their point of view, and possibly ask or answer questions. It also provides the Board with the information it needs to make a fair and objective decision. A panel of no fewer than three NEB board members hears the evidence and then makes the decision to approve or deny an application.

The NEB can monitor the company’s performance in several ways, one of which is through field inspections carried out by NEB Inspection Officers and specialized staff. They monitor the company’s activities to make sure it is meeting the conditions that the NEB has set.

2.1.4 *Canadian Environmental Assessment Act*

The *Canadian Environmental Assessment Act* (*CEAA*) came into force in 1995 to ensure environmental review (including cumulative effects assessment and public consultation) on a project specific basis. Subsection 5(1) of *CEAA* states that an environmental assessment under *CEAA* must be prepared under the following circumstances:

- a federal authority is the proponent of a project;
- a project is being financed in whole or part by a federal authority;
- a project is being conducted on federal lands; or
- a federal authority is issuing a permit, license or approval for a project.

The federal department or agency that triggers the environmental assessment becomes a responsible authority under *CEAA* and must ensure that the proponent conducts an environmental assessment for the proposed project. Examples of departments or agencies who may be responsible authorities for watercourse crossings include DFO, NEB, Parks Canada and Indian Oil and Gas Canada. Coordination of such Federal Authorities under *CEAA* is regulated by the Regulations Respecting the Coordination by Federal Authorities of Environmental Assessment Procedures and Requirements (Canadian Environmental Assessment (CEA) Agency 1997b). There are four regulations under *CEAA* specifying which pipeline projects are subject to environmental assessment: the Exclusion List Regulations, the Law List Regulations, the Comprehensive Study List Regulations and the Inclusion List Regulations.

In the event that piece of legislation listed under *CEAA* Section 5 triggers an environmental assessment on a segment of the route (*e.g.,* Indian Reserve or river crossing as a result of a Subsection 35(2) or 32 authorization under the *Fisheries Act*), the Responsible Authority will establish the scope of the project and the scope of the assessment and undertake the appropriate review process under *CEAA*.

Environmental assessments conducted by the RA must consider cumulative effects caused by the project in combination with other projects or activities that have been or will be carried out. Cumulative effects evaluations consider the combined effects now known to take place over larger study areas and longer time frames. The level of effort should be appropriate to the number of crossings being considered, other existing watershed disturbances, and the combined risk to fish and fish habitat. Additional information is provided in Section 4.3.3 of this report.

Exclusion List Regulations identify those physical works that will not require an environmental assessment under *CEAA* due to the lack of significant environmental effects associated with them. All other physical works require an environmental assessment. Based on the Exclusion List Regulations, those watercourse crossing projects that will not require an assessment under *CEAA* include:

- Section 1 — The proposed maintenance or repair of an existing physical work not in a nationally protected area or site.
- Section 33 — The proposed construction, installation, expansion or modification of a fish habitat improvement structure that would not involve the use of heavy machinery.

The Law List Regulations itemize the statutory and regulatory project approvals that trigger an environmental assessment under the *CEAA* before a project proceeds. The main federal acts and regulations which will trigger an assessment for a pipeline associated watercourse crossing include:

- *Fisheries Act*
  - Section 22 — Provision of flow of water and passage of fish.

- Section 32 — Authorization by MFO to destroy fish by means other than fishing (*e.g.*, blasting, dewatering).
- Subsection 35(2) — Authorization by MFO for the harmful alteration, disruption or destruction of fish habitat in a watercourse.
- Subsection 37(2) — The modification, restriction or closure of a project or Order made with the approval of Governor in Council, when an offence under Subsection 40(1) or 40(2) of the *Fisheries Act* is being or is likely to be committed.

- *Navigable Waters Protection Act*
  - Subsection 5(1)(a) — Approval by TC for the construction of works in navigable waters.
- *NEB Act*
  - Section 52 — Approval by the NEB for the pipelines >40 km in length.
  - Section 58 — Approval by the NEB for pipelines <40 km in length.
  - Section 108 — Approval to cross navigable waters.

The Comprehensive Study List Regulations outline which major projects will require a more comprehensive environmental assessment under *CEAA*. Projects which will require comprehensive study include:

- Subsection 14(a) — The proposed construction of an oil and gas pipeline more than 75 km in length on a new right-of-way.

Information regarding content and process for all levels of environmental assessments is described in the *CEAA* document *The Responsible Authorities Guide to the Canadian Environmental Assessment Act* (CEA Agency 1994). Information requirements for comprehensive study are described in the CEA Agency document *Guide to the Preparation of a Comprehensive Study for Proponents and Responsible Authorities* (CEA Agency 1997a).

The Inclusion List Regulations outline the physical activities that may require environmental assessment. This includes, amongst others, activities which may be affected by the:

- *National Parks Act*;
- *Canada Oil and Gas Operations Act*;
- *Fisheries Act*;
- crossing of Aboriginal lands;
- *Migratory Birds Convention Act*; and
- crossing watercourses in the Yukon, Northwest or Nunavut territories.

2.1.5 Indian Oil and Gas Act

The *Indian Oil and Gas Act* is administered by Indian Oil and Gas Canada. The *Act* pertains to all oil and gas activities on Indian reserve land in Canada south of the 60th parallel. Proponents of a pipeline transporting products from a well located on reserve lands that entails a watercourse crossing on reserve lands will require approval from Indian Oil and Gas Canada. It should be noted that proponents of pipelines that traverse reserve lands but do not transport products from a well on reserve lands must conduct an EA under *CEAA* with Indian and Northern Affairs Canada (INAC) serving as the Responsible Authority. In the event that watercourse crossings are proposed within land claim areas, proponents are advised to discuss the project with INAC, Indian Oil and Gas Canada and DFO.

2.1.6 Canada Oil and Gas Operations Act

The *Canada Oil and Gas Operations Act* is administered by the NEB. The *Act* applies to the exploration, drilling, production, conservation, processing and transportation of oil and gas in the Northwest Territories, Nunavut, Sable Island, or offshore waters of Canada (not including interprovincial and international transmission pipelines, which are regulated by the *NEB Act*). Proponents are required to submit an application, as per the regulations, to the NEB, for a watercourse crossing in these areas. Proponents operating in Nova Scotia and Newfoundland and Labrador will also have to recognize the Atlantic Accords between the federal government and these provinces.

2.1.7 Species At Risk Act

The *Species At Risk Act* is administered primarily by Environment Canada, Canadian Wildlife Service with assistance from DFO for aquatic species and Parks Canada Agency for species on federal lands that are protected as defined in the *Parks Canada Agency Act*. The *Act* protects listed terrestrial species at risk on federal lands, all migratory birds listed by the *Migratory Birds Convention Act* on any lands and all listed aquatic species at risk in any waterbody. The *Act* prohibits killing, harming or harassing listed species, trading in the parts of listed species and damaging or destroying the residence of an individual of a listed species. Proponents should ensure that no listed species at risk could be affected by their project.

2.1.8 Migratory Birds Convention Act

The *Migratory Birds Convention Act* is administered by Environment Canada, Canadian Wildlife Service. The *Act* implements a treaty between Canada and the United States that coordinates a system to prevent the indiscriminate harvest or destruction of migratory birds. The *Act* specifically prohibits the destruction of the nest, eggs and young of migratory birds but does not specifically protect habitat.

Disruption of nests located in riparian habitat by watercourse crossing projects may have implications under the *Act*.

2.2 Provincial and Territorial Jurisdictions

Each provincial and territorial jurisdiction has various legislation, regulations, Codes of Practice, policies and guidelines affecting watercourse crossings. Provincial and territorial jurisdiction generally provides for the approval and regulation of the construction, operation and abandonment of oil and gas pipelines by provincially regulated proponents for a pipeline contained within the boundaries of one province. Interprovincial or international pipelines are also regulated at a federal level under the NEB (see Section 2.1), but may still require provincial approval and need to follow provincial legislation.

Most provinces and territories require a permit, license and/or other authorization to use, affect or potentially affect, surface water and/or make alterations to stream beds and banks. The review of applications to alter stream beds and banks will involve the appropriate provincial fisheries management agencies and may include DFO depending on the agreement the province or territory has with DFO (see Section 2.1 for more detail). Various conditions regarding construction schedule and techniques as well as required mitigative and restoration measures are usually appended to the approval document. The issuance of a permit or license generally does not exempt the applicant from the provision of any other applicable provincial or federal legislation, or any other processes of law including municipal by-laws.

The bed and banks of a watercourse are, in most instances, considered public lands in all provinces and territories in Canada. Proponents must apply to the appropriate provincial or territorial land agency for approval to cross these lands.

An overview of the regulatory requirements for each province and territory with regard to watercourse crossings is provided below. These requirements pertain to watercourse crossings only and it is assumed that the proponent will apply for any federal or provincial pipeline and/or oil and gas approvals required in addition to those listed above and below.

First Nations self-government, land claims and protocols are an ever-changing consideration in the approval processes. Documenting these requirements and recommendations are beyond the scope of this document. Nevertheless, to facilitate a timely review and approval, it is important that all proponents and regulators become familiar with the relevant agreements and other requirements. To ensure timely review and approval, it is beneficial that the appropriate applicable First Nations be incorporated into the construction planning process.

2.2.1 Alberta

Alberta Environment (AENV) and Alberta Sustainable Resources Development (ASRD) are the main provincial departments with responsibilities for pipeline associated watercourse crossings. There are currently three acts and their associated regulations and codes of practice under which a crossing may be regulated:

- *Water Act*
  - Codes of Practice
- *Environmental Protection and Enhancement Act*
  - Conservation and Reclamation Regulation
- *Public Lands Act*
  - Public Lands Pipeline Regulations

The *Water Act* and Ministerial Regulations allow for certain activities to be regulated by a Code of Practice. Currently there are two applicable Codes of Practice, *Code of Practice for Pipelines and Telecommunication Lines Crossing a Water Body* and *Code of Practice for Watercourse Crossings* (*e.g.*, culverts and bridges). Projects that fall under these Codes of Practice do not require *Water Act* approval, however, the Director in the Regional Area where the project is located must be given notice that a pipeline crossing(s) or watercourse crossing is going to be constructed.

The Codes of Practice set out engineering and aquatic environment protection standards that must be met for the construction of a pipeline or telecommunications line crossing a waterbody or watercourse crossing. The owner of the crossing must prepare a plan which includes specifications and written instructions as to when and how the crossing is to be constructed and that the standards of the Codes of Practice are met. There is a requirement that the engineering design for the pipeline or watercourse crossing be prepared by a professional engineer. To ensure that the aquatic environment is protected, any adverse impacts on the aquatic environment resulting from the construction of the crossing, must be fully mitigated. The proponent/owner must follow Schedule 1 of the Codes of Practice or have a qualified aquatic environment specialist prepare a plan that would ensure that the aquatic environment is protected. Background information on the Codes of Practice can be obtained from AENV.

Additional permits and approvals for pipeline associated watercourse crossings required under the *Environmental Protection and Enhancement Act* and the *Public Lands Act*, are discussed below.

Conservation and Reclamation (C&R) approval is required under the *Environmental Protection and Enhancement Act* for all Class 1 pipelines (pipeline index = mm O.D. x km $\geq$2690) in the White Area and requires proponents to submit C&R report. Class 2 pipelines (pipeline index <2690) in the White Area do not require a C&R approval but are still subject to AENV Guidelines (Alberta Environmental Protection (AEP) 1994a,b,c). An Environmental Field Report

(EFR) is required for all pipelines on public land (White and Green Areas) and for any pipeline in the Green Area, regardless of its index or ownership of the land on which it is built.

Approval under the *Public Lands Act* will only be required if public land is adjacent on both sides of the watercourse or if the proponent or ASRD requests an approval. To determine if an approval will be required and to obtain application forms, contact the ASRD Public Lands and Forest office nearest to the proposed activity.

Pipeline Agreements (PLAs) are required under the *Public Lands Act* to use Public land (*i.e.*, bed and banks of a watercourse).

Alberta has several provincial guidelines applicable to pipeline associated watercourse crossings:

- Fisheries Habitat Protection Guidelines
  - *Guideline 3 - Pipeline Construction and Stream Crossing*" (Alberta Forestry, Lands and Wildlife 1987)
  - *Guideline 4 - Vehicular Access Across Watercourses* (AEP 1992a)
  - *Guideline 6 - Timing Constraints on Construction In and Around Watercourses* (Alberta Forestry, Lands and Wildlife 1992c)
  - *Guideline 7 - Timber Harvesting and Fish Habitat* (Alberta Forestry, Lands and Wildlife 1985b)
  - *Guideline 10 - Water Intakes: Screen Requirements for Fisheries* (Alberta Forestry, Lands and Wildlife 1993)
  - *Guideline 15 - Use of Explosives in the Water* (Alberta Forestry, Lands and Wildlife 1987c)
- *Stream Crossing Guidelines: Operational Guidelines for Industry* (Alberta Energy and Natural Resources 1985).
- *Design Guidelines and Application Procedures for a Bridge, Culvert or Other Structure Crossing a Watercourse or Waterbody* (Alberta Environment 1990).
- *Design Guidelines and Application Procedures for Buried Pipeline(s) Crossing a Watercourse or Waterbody* (AEP 1994).
- *Environmental Protection Guidelines for Pipelines - C&R IL 94 5* (AEP 1994b).
- *Guide for Pipelines Pursuant to the Environmental Protection and Enhancement Act and Regulations* (AEP 1994c).
- *Conservation and Reclamation Guidelines for Alberta - C&R IL 97-1* (AEP 1997a).
- *Guidelines for the Application of Fish and Wildlife Conditions to Land Use Activities in Northeastern Slopes Region* (Draft) (AEP 1997b).

As of December 1997, AENV has no longer been actively participating in the federal regulatory processes involving fish habitat and navigable waters protection as they pertain to the *Fisheries Act* and the *NWPA*. Proponents are advised compliance with the Code of Practice or issuance of licences, authorizations and approvals by AENV or ASRD under the *Environmental Protection and Enhancement Act*, *Water Act* or the *Public Lands Act* does not mean the project has federal approval. If concerned about their project meeting the requirements of the *Fisheries Act*, proponents are encouraged to discuss their project with DFO.

2.2.2 British Columbia

In British Columbia (B.C.), the Ministry of Environment (MOE) and the B.C. Oil and Gas Commission are the main provincial regulating agencies for watercourse crossings. Several pieces of legislation which pertain to pipeline associated watercourse crossings are identified below:

- *Environmental Assessment Act*
  - Environmental Assessment Reviewable Projects Regulation
- *Oil and Gas Commission Act*
- *Fish Protection Act*
- *Forest Practices Code of British Columbia Act*
- *Land Act*
- *Water Act*
  - Water Regulation

Pipelines are "reviewable" under the *Environmental Assessment Act* by MOE if the construction of a new facility:

- is a transmission pipeline in accordance with one of the following dimensions;
  - <114.3 mm O.D., 60 km or more,
  - >114.3 and <323.9 mm O.D., 50 km or more,
  - >323.9 mm O.D., 40 km or more; or
- has the capacity to transport in one year an energy resource or solid in a quantity that can yield by combustion 16 PJ or more of energy.

The Minister may require other smaller projects to be reviewed under the *Environmental Assessment Act* if it is felt the project may have a significant adverse effect on the environment or if it is in the public interest to do so. Section 7 of the *Environmental Assessment Act* provides details on what information requirements must be submitted on the application to MOE.

All provincially regulated oil and gas projects are reviewed by the B.C. Oil and Gas Commission. Proponents must complete consultation with government and stakeholders and submit an application form to the Commission. The Commission will then assess the project, conduct further consultation if required and provide a decision or approval for the project. If an environmental assessment is triggered under the *Environmental Assessment Act*, approval from MOE will be required prior to submitting the application to the B.C. Oil and Gas Commission.

The *Fish Protection Act* provides for the protection of water flows for fish, designation of "sensitive streams" requiring stronger management measures, protection of fish habitat and improved riparian protection. Watercourse crossings will be subject to the *Fish Protection Act* and require compliance prior to the issuance of licenses and approvals by regional water managers.

The *Water Act* has undergone some changes with respect to the *Fish Protection Act*. Fish habitat protection must be considered when applying for licenses under the *Water Act*. Proponents are responsible for all debris entering a watercourse and must remediate or mitigate the effects of the introduction, as authorized by the regional water manager.

In B.C., all watercourses are considered to be fish-bearing or have the potential to be fish-bearing unless proven otherwise (generally with at least two sampling seasons). Proponents must conduct a fisheries assessment for each watercourse crossing in which instream construction will take place. Fisheries assessments are also advised for bored or horizontal directionally drilled crossings where a contingency plan with instream construction will be initiated if drilling is not successful. Fisheries assessments must be conducted in accordance with recognized fish and fish habitat sampling methods and standards (Resources Inventory Committee (RIC) 1997, 1999, 2001; B.C. Forest Service 1998).

B.C. has several provincial codes of practices, guidelines and guides applicable to watercourse guidelines that are identified below:

- *Standards and Best Practices for Instream Works* (MWLAP 2004).
- *Stream Crossing Planning Guide* (Northeast B.C.) Version 2.0 – December 15, 2004 (B.C. Oil and Gas Commission 2004a).
- *Fish Stream Identification and Risk Management Tool* (B.C. Oil and Gas Commission 2004b).
- *Fish and Wildlife Timing Windows Document and Table* (B.C. Oil and Gas Commission 2004c).
- *Schedule A, Approved Sources of Water* (B.C. Oil and Gas Commission 2004d).
- *Forest Practices Code of British Columbia: Fish-stream Crossing Guidebook* (B.C. Forest Service, MWLAP, and MEM 2002).
- *Forest Practices Code of British Columbia: Riparian Management Area Guidebook* (B.C. Forest Service 1995a).
- *Oil and Gas Commission Planning Guide for Oil and Gas Operations in British Columbia* (B.C. Oil and Gas Commission 2004e).
- *Forest Road Engineering Guidebook* (B.C. Forest Service 1995b).
- *Northern Interior Region - Peace / Liard Sub-Region Stream Impact Guidelines* (B.C. Ministry of Environment, Lands and Parks 1991).
- *Terms of Reference For Impact Assessments Adjacent To Proposed Pipeline Crossings* (B.C. Ministry of Environment, Lands and Parks 1992).

DFO has developed *Land Use Guidelines for the Protection of Aquatic Habitat*, which are specifically designed for B.C. (DFO 1992). These guidelines pertain to the federal *Fisheries Act*.

2.2.3 Manitoba

The departments of Conservation and Water Stewardship are the main regulatory agencies for watercourse crossings. There are four pieces of legislation noted below which pertain to pipeline associated watercourse crossings:

- *Environment Act*
- *Water Resources Administration Act*
- *Crown Lands Act*
- *Water Rights Act*

A Manitoba *Environment Act* License is required for those projects that are likely to have a significant effect on the environment including construction and replacement of watercourse crossings. To acquire a license, an application must be submitted to the Environmental Approvals Branch of Manitoba Conservation. Manitoba Conservation, Water Stewardship and other relevant federal and provincial departments will review the application. Fish and fish habitat protection measures are often included as conditions to the license for approved projects. Work permits may also be required under the *Environment Act* licenses and are used to ensure habitat is adequately protected in the manner described in the *Environment Act* License. Work permits are issued for a variety of activities including watercourse crossing installation and any activities which may alter the aquatic habitat.

Manitoba Conservation, Programs Division, Lands Branch, under the authority of the *Crown Lands Act*, must be contacted for regulatory approval of watercourse crossings under the *Act*. Most lands in Manitoba below the average annual high water level are Crown lands. Provincial Work Permits are used to authorize activities taking place on Crown land. These permits are generally issued by the District Natural Resources Officer (NRO) where the activity is occurring and the District is also responsible for ensuring that the conditions of the Work Permit are met.

Under the *Water Resources Administration Act*, a proponent must obtain a permit to undertake instream or nearshore construction in a designated river, stream or area (up to 350 feet from the normal summer water mark). Deposition of any material that may impede or restrict the flow of water or affect bank stability as well as the construction of a structure that may affect bank stability is prohibited, unless authorized by issuance of a permit.

Under the *Water Rights Act*, a proponent must obtain a license to use or divert water in any matter, or to construct any works that may divert water. The permit or license application is made to the Water Branch of the Department of Water Stewardship. The Fisheries Branch also reviews the application and will provide recommendations based on fishery resources considerations.

In Manitoba, if an open cut is required within a restricted construction timing window (*i.e.,* spawning and incubation season) an Authorization under Subsection 35(2) of the federal *Fisheries Act* will be required from DFO.

Guidelines for watercourse crossings were published by Manitoba Natural Resources and DFO in 1996: *Manitoba Stream Crossing Guidelines for the Protection of Fish and Fish Habitat*.

Fish habitat management is coordinated between federal and provincial levels in Manitoba by a Memorandum of Understanding between Fisheries and Oceans Canada and Manitoba Conservation. The Memorandum of Understanding establishes the Canada/Manitoba Fish Habitat Committee that has the mandate of developing clear, concise and coordinated principles for fish habitat management by Canada and Manitoba.

2.2.4 New Brunswick

The New Brunswick Department of Natural Resources and Department of Environment and Local Government administer most aspects of pipeline associated watercourse crossings. Crossings are subject to the following legislation:

- *Clean Environment Act*
  - Environmental Impact Assessment Regulation
- *Clean Water Act*
  - Watercourse and Wetland Alteration Regulations
- *Crown Lands Act*
- *Fish and Wildlife Act*
- *Quarriable Substances Act*

The approval and regulation of the construction and operation of oil and gas pipelines in New Brunswick are provided for by the Environmental Impact Assessment Regulation of the *Clean Environment Act*. All oil and gas pipelines exceeding 5 km in length are designated by this Regulation as projects which may result in significant environmental impact. These undertakings must be registered with the Minister of Environment to determine whether the preparation of an environmental impact assessment is required.

DFO retains direct management control of fisheries in New Brunswick. However, authorization for watercourse alteration is required from the New Brunswick Department of Environment and local government through the Watercourse and Wetland Alteration Permit. The New Brunswick Watercourse and Wetland Alteration staff will review the Application and may request input from DFO and/or the New Brunswick Department of Natural Resources. No separate applications to these agencies are required, but both agencies are responsible for their own legislation and attainment of their goals and objectives. The New Brunswick Department of Natural Resources is responsible for the *Crown Lands Act*, the *Quarriable Substances Act* and the *Fish and Wildlife Act*.

The New Brunswick Watercourse Alteration Technical Committee is comprised of representatives from both provincial and federal government agencies and has prepared *Watercourse Alteration Technical Guidelines* (New Brunswick Watercourse Alteration Technical Committee 1987).

2.2.5 Newfoundland and Labrador

The Newfoundland and Labrador Department of Environment and Conservation is responsible for the approval of pipeline associated watercourse crossings in Newfoundland and Labrador. Crossings are subject to the following legislation:

- *Environmental Protection Act*
  - Environmental Assessment Regulations
- *Water Resources Act*

Pursuant to the Environmental Assessment Regulations of the *Environmental Protection Act*, pipelines located a distance greater than 500 m from an existing right-of-way must be registered and reviewed by the Minister of Environment and Conservation. An environmental preview report may be required to determine whether further environmental assessment is required or any significant adverse environmental impact is indicated. Alternatively, a proponent may proceed directly with the preparation of an environmental impact statement.

Any alteration of a body of water, including a watercourse crossing, is an undertaking requiring approval under section 48 of the *Water Resources Act*. The approval must be obtained from the Department of Environment and Conservation, Water Resources Management Division and the application requires pertinent information relating to engineering, hydraulic design, site features, construction operations and anticipated engineering implications.

DFO retains direct management of fisheries of Newfoundland and Labrador. Authorizations may be required under the federal *Fisheries Act*.

2.2.6 Northwest Territories

Approval and regulation of oil and gas pipelines in the Northwest Territories (NWT) is administered by a number of different agencies and is dependent upon which region of the NWT the pipeline project will take place. The following descriptions illustrate the current regulatory environment in the NWT, but should not be considered prescriptive. Besides regional regulation, it is important to consider that overall the NEB administers, approves and regulates oil and gas pipelines and DFO retains direct management control of fisheries resources in the NWT.

Inuvialuit Settlement Region

In the Inuvialuit Settlement Region (ISR), the Inuvialuit Land Administration (ILA), is responsible for administering and managing the lands received under the Inuvialuit Final Agreement. All oil and gas applications involving use of Inuvialuit lands are filed with the ILA, which then forwards the applications to the Inuvialuit Environmental Impact Review Board for review and recommendations. Land use permits are granted by the ILA on Inuvialuit private lands and by INAC on Crown lands according to Territorial Land Use Regulations of the *Territorial Lands Act*. The NWT Water Board issues all water licences according to the *Northwest Territories Waters Act.*

Mackenzie Valley

Developments in the Mackenzie Valley are subject to the regulatory regime established by the *Mackenzie Valley Resource Management Act*. The *Act* establishes regional land and water boards for both the Gwich'in and Sahtu settlement areas for developments that will take place wholly within the settlement area boundaries. In addition, the *Act* designates the Mackenzie Valley Land and Water Board as the authority for unsettled claims areas and transboundary projects.

All land and water boards are responsible for the issuance of land use permits and water licences, both of which would be required for a watercourse crossing. Determination criteria for land use permits are set out in the Mackenzie Valley Land Use Regulations and water licences are issued pursuant to the *Northwest Territories Waters Act*. If necessary, permit and license applications will be forwarded to the Mackenzie Valley Environmental Impact Review Board for environmental assessment and review.

2.2.7 Nova Scotia

DFO retains direct control of the fisheries of Nova Scotia. However, the Nova Scotia Government administers other provincial acts and regulations noted below.

- *Crown Lands Act*
- *Environment Act*
  - Activities Designation Regulations
  - Approvals Procedure Regulations
  - Environmental Assessment Regulations

The *Environment Act* requires that all projects altering a watercourse or its flow obtain a Water Approval for Watercourse Alteration from the Nova Scotia Department of Environment and Labour. Applications may be referred to other relevant provincial agencies or to DFO and TC for assessment.

All proposed pipelines require Environmental Assessment Approval under the *Environment Act*. The Approvals Procedure Regulations provide proponents with the application process to be followed for the assessment. A Use of Crown Lands Permit is required from the Nova Scotia Department of Natural Resources for all right-of-way crossings (*i.e.*, bed and banks).

2.2.8 Nunavut

Land use activities on Crown lands in Nunavut are regulated by the Territorial Land Use Regulations of the *Territorial Lands Act*. Land use permit applications are submitted to INAC who then forwards the application to the Nunavut Impact Review Board (NIRB). The NIRB was set up under Article 12 of the Nunavut Land Claim Agreement to examine potential development impacts for proposed projects. The NIRB may be required to assess the ecosystemic and socio-economic impacts of the project to determine whether the project should proceed to development and if so, under what conditions. NIRB will forward the application to DFO for review.

Applications for land use activities on Inuit Owned Lands (IOL) are submitted to the appropriate regional office of the Nunavut Planning Commission:

- North Baffin Planning Region – Pond Inlet
- North Baffin Planning Region – Iqaluit
- Akunniq Planning Region – Taloyoak
- Keewatin Planning Region – Arviat
- Sanikiluaq Planning Region – Iqaluit (interim)
- West Kitikmeot Planning region – TBA

Water license applications are submitted to the Nunavut Water Board (NWB) pursuant to the *Nunavut Waters and Nunavut Surface Rights Tribunal Act*. The NWB contributes fully to the assessment of development plans as they concern water in Nunavut. All water crossings, water uses or disposals of waste into water must be approved by the NWB.

2.2.9 Ontario

Watercourse crossings in Ontario are administered by the Ontario Ministry of Natural Resources (OMNR) in consultation with DFO and the Ontario Conservation Authority.

OMNR reviews all aspects of a proposed watercourse crossing and all projects will require a Work Permit from their office. If Crown lands are involved the permit is issued under the *Public Lands Act* and if private or municipal lands are involved the permit is issued under the *Lakes and Rivers Improvement Act*. Proponents should follow the procedures described in *Environmental Guidelines for Access Roads and Water Crossings* (OMNR 1993b).

Proponents of large pipeline projects should contact DFO directly to determine whether a crossing requires an Authorization under Subsection 35(2) of the *Fisheries Act*. DFO will either grant an Authorization or supply a letter of advice to the proponent suggesting measures to avoid HADD. If it is not feasible to avoid HADD and the impacts on fish habitat are unacceptable, an Authorization will not be issued. DFO monitors isolated and trenchless crossings and requires a list of the locations of all such crossings from proponents.

In southern Ontario, proponents must also obtain a permit from the appropriate Conservation Authority for all watercourse crossings. The authority will issue a permit provided the construction of the crossing will not affect the control of flooding or pollution, or conservation of land.

OMNR has developed generic drawings for dam/pump and flume crossing techniques and temporary access bridges. All open trenched crossing techniques will require a more extensive application and submission of a Sediment Control Plan. Information requirements for a Sediment Control Plan and copies of OMNR Generic Drawings can be obtained from OMNR offices.

There are several documents regarding guidelines and policies for pipeline associated watercourse crossings in Ontario; they are listed below.

- *Guidelines for Evaluating Construction Activities Impacting on Water Resources* (Ontario Ministry of Environment and Energy 1995).
- *Water Management - Goals, Policies, Guidelines, Objectives and Implementation Procedures of the Ministry of the Environment* (Ontario Ministry of the Environment 1984b).
- *Ontario Generic Sediment Control Plans* (Ontario Ministry of Natural Resources 1993a).
- *Sediment Control Plans for Wet Crossings* (Ontario Ministry of Natural Resources 1993b).
- *Environmental Guidelines for Access Roads and Water Crossings* (Ontario Ministry of Natural Resources 1993b).
- *Ontario Energy Board Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (Ontario Energy Board 1995).
- *Instream Sediment Control Techniques Field Implementation Manual* (Trow Consulting Engineers Ltd. 1996).
- *Fisheries-related Information Requirements for Pipeline Water Crossings* (Goodchild and Metikosh)

2.2.10 Prince Edward Island

Approval and regulation of pipeline associated watercourse crossings on Prince Edward Island (PEI) is administered by the PEI Department of Environment, Energy and Forestry under the *Environmental Protection Act*. The proponent must provide a written proposal to the department with regard to the project. The

Minister may request further information or ask the proponent to develop an environmental impact statement, as well as provide public notification and input.

DFO retains direct management control of fisheries for PEI; however, a Watercourse Alteration Permit is required from the PEI Department of Fisheries, Aquaculture and Environment. The review process for this permit includes comment from DFO. The Minister has appointed the PEI Watercourse Alteration Advisory Committee to review applications for watercourse alteration permits and to advise the Minister on these proposed projects. The Committee and DFO developed watercourse alteration guidelines in 1989 (PEI Watercourse Alterations Advisory Committee 1989).

2.2.11 Québec

Watercourse crossings in Québec are subject to provisions under the *Loi sur la qualité de l'environnement* and the *Loi sur la conservation et la mise en valeur de la faune*.

Major pipeline associated watercourse crossings in Québec are subject to Articles 22 and 31.1 from the *Loi sur la qualité de l'environnement* and require an Environmental Impact Assessment as well as Public Hearings. Applications for major projects are submitted to the Ministère de l'Environnement. Major projects are defined as one or both of the following:

- Involves dredging, digging, filling, leveling or backfilling of 300 m in length or larger or an area of 5,000 m^2 or more (up to the high water mark) in a "river"; or
- Temporarily or permanently rerouting or diverting a "river".

To determine if the watercourse is classified as a "river" one must consult the Répertoire de ponymique.

Minor pipeline associated watercourse crossings in Québec are subject to Article 22 from the *Loi sur la qualité de l'environnement* and if the watercourse is public property the *Loi sur la conservation et la mise en valeur de la faune*. Applications are submitted to the Regional Directors of the Ministère de l'Environnement for Article 22 and to the Regional Director of La Société de la Faune et des Parcs du Québec if the watercourse is public property. However, if the project follows the regulations set out in the *Loi sur la conservation et la mise en valeur de la faune* then the proponent does not need to obtain authorization from La Société de la Faune et des Parcs du Québec. If the project occurs in a forested area, authorization is still obtained from La Société de la Faune et des Parcs du Québec and not from the Ministère des Resources Naturelles, since the *Loi sur les forêts* includes the regulations from the *Loi sur la conservation et la mise en valeur de la faune* in regard to water crossings.

The Ministère de l'Environnement has guidelines listed in a publication entitled Critères d'analyse des projects en milieux hydrique, humide et riverain assujettis à l'article 22 de la *Loi sur la qualité de l'environnement* published in December 1996 which contains 20 articles on various related subjects such as:

- Fîche 1: Stabilisation naturelle des rives (Natural Stabilization of Creeks);
- Fîche 4: Dragage et creusage (Dredging and Digging);
- Fîche 8: Pont et ponceau (Bridges and Culverts);
- Fîche 9: Traversée de cours d'eau (Water Crossing);
- Fîche 10: Détournement et redressement de cours d'eau (Rerouting and Diversion of Watercourses); and
- Fîche 14: Prises d'eau (Water Sampling)

2.2.12 Saskatchewan

Pipeline associated watercourse crossings in Saskatchewan are regulated by Saskatchewan Environment under the following legislation.

- *Environmental Assessment Act*
- *Environmental Management and Protection Act*
  - Water Regulations, 2002

Saskatchewan Environment requires proponents to apply for a Shoreland Alteration Permit (SAP) and/or an Aquatic Habitat Protection Permit (AHPP) for all watercourse crossings.

Several watercourse crossing guideline documents proposed for Saskatchewan are identified below:

- *Fish Habitat Protection Guidelines: Road Construction and Stream Crossings* (Fisheries and Oceans and Saskatchewan Environment and Resource Management 1995)
- *Environmental Operating Guidelines for the Saskatchewan Petroleum Industry* (Canadian Petroleum Association 1992).
- *Guidelines for Preparation of an Environmental Protection Plan for Oil and Gas Projects* (Saskatchewan Environment 1987).

2.2.13 Yukon

Approval and regulation of the construction and operation of oil and gas pipelines in the Yukon is administered by Natural Resources Canada and the NEB. DFO has management control of marine and anadromous fisheries resources and management of all fisheries habitat. First Nation Renewable Resources Councils are responsible for non-anadromous fisheries and fulfill their responsibilities in consultation with DFO.

Watercourse crossings are subject to the following territorial legislation:

- *Yukon Environmental and Socioeconomic Assessment Act (YESAA)*

- *Territorial Lands (Yukon) Act*
- *Waters Act*
  - Waters Regulations, 2002

The Development Assessment Process (DAP) established by the *Yukon Environmental and Socioeconomic Assessment Act* was negotiated under the Yukon First Nations Umbrella Final Agreement and provides a comprehensive, integrated environmental assessment process that applies to First Nations settlement lands, Commissioner's (Territorial) lands and federal Crown lands. The YESAA Board and the Yukon Government Executive Council Office, DAP Branch oversee the administration of the *Act*.

The Yukon Water Board is responsible for the issuance of all water licences under the *Waters Act*.

Land use permitting of land under the control of the Yukon government is conducted through the Department of Energy, Mines and Resources. Yukon First Nations have control over their individual settlement lands and must be contacted regarding proposed pipeline associated watercourse crossings within their jurisdiction. The Yukon Land Use Planning Council is in place to co-ordinate First Nation and Government land use planning.

3 Description of Crossing Techniques

This section presents two tables summarizing the environmental and engineering/construction considerations for each pipeline and vehicle crossing technique. The intent is to allow the reader to become aware of the advantages and disadvantages of each technique and factor this information into the watercourse crossing planning process.

3.1 Pipeline Crossings

This sub-section outlines the various pipeline watercourse crossing construction techniques commonly used in Canada. **Table 3.1** summarizes the environmental and construction advantages and disadvantages as well as the appropriate uses of each crossing method of construction. Drawings 1 to 11 (see Appendix A) outline the standard protection measures that should be incorporated with each technique. Although the appropriate uses for each technique are identified, implementation of alternative techniques with mitigation measures or a combination of techniques may also be applicable. Since the drawings and measures contained in this document are typical and not site-specific, detailed design drawings might be required with input from an engineer and other specialists.

3.2 Temporary Vehicle Crossings

This sub-section outlines the various vehicle crossing techniques that can be used during the construction of pipeline associated crossings. **Table 3.2** summarizes the environmental and construction advantages and disadvantages as well as the appropriate uses of each technique. Drawings 12 to 15 (see Appendix A) illustrate the more common techniques and outline the standard environmental protection measures that should be implemented with each crossing method. Typical vehicle crossing drawings should be designed by an engineer with input from other specialists to meet regulatory requirements. In most situations, typical drawings similar to those contained in this document will be sufficient; however, where site-specific cases warrant, or where special vehicle crossing techniques are necessary, individual crossing designs by an engineer should be considered.

Table 3.1 Pipeline Watercourse Crossing Construction Techniques

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
OPEN TRENCHED i) Plow (see Dwg. 1)					
• plow-in pipeline without pretrenching • feed or drag pipeline into furrow behind plow	• rapid construction / installation • minimizes period of instream activity • minimizes total sediment release • short period of sediment release • minimal temporary workspace required	• grading of banks required • potential sediment release during grading of banks • sediment release during instream work • removal of riparian vegetation	• reduces instream activity • eliminates backfilling phase • low cost if equipment onsite • rapid construction / installation	• specialized equipment • need access ramps to creek • problematic in boulders and bedrock • depth of cover is limited	• unconsolidated substrate (*e.g.,* sand or gravel) • shallow lakes or watercourses with little or no flow (<1 m) • when pipeline on uplands is also being plowed-in • small diameter lines (<168.3 mm O.D.) • where instream work is permitted but sediment release is to be minimized
OPEN TRENCHED ii) Bucket / Wheel Trencher					
• trench through watercourse with bucket / wheel trencher	• rapid construction / installation • minimizes period of instream activity • short period of sediment release	• potentially high sediment release • spoil pile may block flow • trench is prone to sloughing • requires extensive grading of banks	• no special equipment • not limited by width of watercourse • low cost • rapid construction / installation	• limited by water depth (<1 m) • trench is prone to sloughing • trench may not be wide enough • equipment has trouble on steep banks • difficulty with rocky substrate or bedrock • trench depth may be inadequate	• dry intermittent water-courses with fine-textured substrate where wheel ditcher is being used on uplands • possibly for low flow, low sensitivity streams with low banks • dry creeks and shallow swales

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
OPEN TRENCHED iii) Hoe (see Dwgs. 2 and 3)					
• trench through watercourse with hoe from banks or instream	• rapid construction / installation • minimizes period of instream activity • generally maintains streamflow • maintains fish passage • relatively short duration of sediment release (<24 hours)	• potentially high sediment release during excavation and backfilling • instream stockpiling of spoil on wide watercourses • may interrupt streamflow	• no need for specialized equipment • rapid construction / installation • low cost • compatible with granular substrates and some rock	• limited to less than 20 m unless hoe works instream • limited by water depth unless hoe works off barge • may require several hoes working together to facilitate excavation	• shallow (<1.5 m) watercourse with unconsolidated granular substrate
OPEN TRENCHED iv) Dragline (see Dwg. 4)					
• trench through watercourse with dragline bucket from either bank	• equipment not in watercourse • spoil on banks • maintains streamflow • maintains fish passage	• potentially high sediment release • slow construction / installation • long duration of sediment release • safety concern with cables strung across watercourse • may require grading of banks leading to sediment release • large area required for equipment	• permits many passes over trench • cleans sloughed material from trench • good for unconsolidated substrate • permits deeper trench	• moderately expensive • inaccurate control on trench width and alignment • slow construction / installation • specialized equipment • trench susceptible to sloughing • need large working space for equipment set up • cables restrict navigational use of watercourse • incompatible with boulders or consolidated bottom material	• wide and deep water-courses with soft substrate and limited navigational concerns • often used to clean out trench initiated with hoes

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	**Disadvantages**	**Advantages**	**Disadvantages**	
OPEN TRENCHED v) Dredging					
• dredge trench through watercourse with suction and pump slurry to banks or tanks on barges	• minimal sediment release during trenching • maintains streamflow • maintains fish passage • no instream spoil storage • relies on natural sediment transport for backfill	• settling ponds required for slurry • disposal of settled water • possible mortality or injury to fish	• allows deep water trenching • technique for transporting to shore • no instream spoil storage	• expensive • specialized equipment • settling pond must be constructed • difficult in large granular substrate or bedrock • trench depth may be inadequate	• deep, wide rivers / lakes with fine unconsolidated substrate • where sediment release is a concern
ISOLATED TRENCHED i) Flume (see Dwg. 5)					
• block flow upstream of crossing and divert through flume pipe(s) laid in streambed perpendicular to pipeline • dam downstream side of crossing area to prevent backflow • flume(s) should be properly sized to accommodate flow • high capacity variations constructed out of 2 m x 3 m x 32 m steel box sections • may be augmented with pump bypass	• limited sediment release • maintains streamflow • may allow fish passage • minimal release and transport of sediment downstream; not likely to result in negative effects to fish and fish habitat. • allows for flushing of substrates	• minor sediment release during dam construction, removal and as water flushes over area of construction • slow construction / installation prolongs sediment release • fish salvage may be required from dried up reach • short-term barrier fish passage if water velocity in culvert is too high	• relatively dry or no flow working conditions • ample time for pipeline construction • may be adapted for nonideal conditions • compatible with consolidated substrates • may incorporate bridge • may reduce ditch sloughing and ditch width	• difficult to trench and lay pipe, especially large diameter pipe, under flume pipe • difficult to install properly • flow limited by flume size 2 - 3 m^3/s using multiple flume pipes >20 m^3/s • moderately expensive • work area may not stay dry in coarse, permeable substrate • too short a flume may not be sufficient for unstable trench • flume pipe can be crushed or blocked during pipeline construction • requires relatively long, straight channel to install flume	• small watercourse with defined banks and defined channel with solid, fine-textured straight substrate • where sediment release and fish passage are of concern • works best in nonpermeable substrate • common usage is for flows <1 m^3/s

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	**Disadvantages**	**Advantages**	**Disadvantages**	
ISOLATED TRENCHED ii) Dam and Pump (See Dwg. 6)					
• dam flow upstream and downstream of crossing and pump water around via hose(s)	• limited sediment release • maintains streamflow • minimal release and transport of sediment downstream; not likely to result in negative effects to fish and fish habitat.	• minor sediment release during dam construction, dam removal and as water flushes over area of construction • slow construction / installation resulting in extended period instream and prolonged sediment release • fish salvage may be required from dried up reach • short-term barrier to fish movement	• relatively dry working conditions • ample time for pipeline construction • may be adapted for nonideal conditions • hose can be routed around area of construction • multiple pumps can be used • compatible with consolidated substrates • can be used in watercourses with meandering channel • may reduce ditch sloughing and ditch width	• size of watercourse limited to pump capacity • specialized equipment and materials • slow construction / installation • moderately expensive • hose(s) may impede construction traffic • seepage may occur in coarse, permeable substrate • susceptible to mechanical failure • requires standby pump(s)	• small watercourse with low flow, defined banks and channel with no requirement for fish passage • where sediment release is of concern • works best in non-permeable substrate • common usage is for flows <1 m^3/s (max. capacity of 1 pump ~0.3 m^3/s)
ISOLATED TRENCHED iii) High Volume Pump Bypass / Sump and Pump (See Dwg. 7)					
• install high volume pump(s) bypass in pool upstream of crossing and pump watercourse dry, discharging down-stream of crossing • construct work area sump downstream of ditch to permit "washing" of work area • pump silt-laden water from sump onto well vegetated area • partial bypass in high flow situations may be used to reduce instream water velocity	• limited sediment release • maintains streamflow • normal streamflow can be restored instantly • no sediment release as a result of dam construction • minimal release and transport of sediment downstream; not likely to result in negative effects to fish and fish habitat.	• minor sediment release as water flushes over area after construction • dries up short reach of streambed • short-term barrier to fish movement • fish salvage may be required from dried up areas • sump areas are required	• no dams are required • flow can be regulated if necessary • hose(s) can be routed around area of construction • multiple pumps can be used • compatibility with consolidated substrates	• sump(s) may need to be excavated • specialized equipment and materials required • moderately expensive • hose(s) may impede construction traffic • requires stand-by pump(s) • susceptible to mechanical failure	• small to moderate watercourses with low to moderate flow (1 m^3/s) and no requirement for fish passage (max. pump capacity ~0.3 m^3/s • partial bypass in high flow situations may be used to reduce instream water velocity

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
ISOLATED TRENCHED iv) Coffer Dam (see Dwg. 8)					
• install dam approximately 2/3 into watercourse surrounding work area • pump area dry or work in "still" waters • remove dam and repeat on other side of watercourse • materials such as regular sandbags, sheet piling, oversized (1 m^3) sandbags, rock fill / median barriers, poly water structures or a combination of the above can be used	• maintains streamflow • maintains fish passage • minimal release and transport of sediment downstream; not likely to result in negative effects to fish and fish habitat.	• moderate sediment release based on amount of instream work • may dry up long reach of watercourse • fish salvage required from dried-up reach • increased water velocity and potential scouring • possible increased erosion on opposite bank • potential washout of dam • slow construction / installation • extensive instream activity with heavy equipment may be required to install dams • requires large right-of-way and terrain disturbance	• relatively dry or no flow working environment • ample time for pipeline construction • compatible with consolidated substrates	• source of dam materials needed (*i.e.,* sandbags, rock fill, poly, etc.) • pumping may be required • expensive • specialized materials • difficult to make tie-in • slow construction / installation • potential washout of dam • safety concerns	• moderate to large watercourses too large for flume or pump techniques • where sediment release and fish passage are of concern • braided stream channels • watercourses with low banks • where an extended instream period is required • isolation of stream banks or portions of streambeds for maintenance and repair works

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
ISOLATED TRENCHED v) Channel Diversion (see Dwg. 9)					
• divert streamflow into existing side channels or abandoned channel or construct a new channel • use rockfill, sheet piling or poly water structures to divert flow • channel may be lined or have a flexible stream diversion conduit installed	• maintains streamflow • maintains fish passage • minimal release and transport of sediment downstream; not likely to result in negative effects to fish and fish habitat.	• unless lined, very high sediment release when new channel is flushed through • dries up long reach of watercourse • fish salvage required from dried-up reach • slow construction / installation • potential washout of diversion dam • damage to streambank and adjacent lands	• relatively dry working area • ample time for pipeline construction • compatible with consolidated substrates	• expensive • source of dam (*i.e.,* sandbags, rock fill, poly, etc.) material needed • may require channel liner or conduit • may require extensive preparation and channel grading / restoration • specialized materials required • slow construction / installation • potential washout of diversion dam	• watercourses too large to flume or pump • best used when new channel is clear of fine substrate and will cause little sediment release • braided stream channels • where sediment release and fish passage are of concern

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
TRENCHLESS i) Boring (see Dwg. 10)					
• bore under watercourse from bellhole on one side to bellhole on other with or without casing • wet boring with pilot hole and reaming bit can also be performed	• no sediment release • no disturbance of streambed or banks • maintains normal streamflow • maintains fish passage • maintains vegetative buffer on either side of watercourse • not likely to result in HADD	• pump(s) may be required to drain seepage within the bellholes onto surrounding lands • possibility of sump water causing sediment release in watercourse • requires additional workspace for bellholes, spoil piles and sump(s) • potential for borehole cave-in and/or dewatering	• can be fast and economical under the right conditions • minimizes clean-up of bed and banks • road boring equipment may be available • may be able to construct during sensitive fisheries restricted activity windows	• can be slow or not feasible under adverse conditions • difficult with till or coarse material • potential for borehole cave-in • excessive borehole depth on deeply incised watercourses or watercourses with moderate or greater approach slopes • with excessive seepage in course fluvial material it may be impossible to keep bell hole dry • seepage into bellhole may cause sloughing • possible need for specialized equipment and pump(s) • limited to approximately 100 m, however, length varies with borehole diameter	• fine-textured impermeable soils • low water table • where streambed cannot be disturbed • used most often on irrigation ditches • where fish / riparian habitat cannot be disturbed • where the watercourse is only slightly incised and approach slopes are absent or slight

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
TRENCHLESS ii) Punching / Ramming (see Dwg. 10)					
• ram or punch casing or pipe under watercourse	• no sediment release • no disturbance of streambed and banks • maintains normal streamflow • maintains fish passage • maintains vegetative buffer on both sides of watercourse • not likely to result in HADD	• pump(s) may be required to drain seepage within the bellholes onto surrounding lands • possibility of sump water causing sediment release in watercourse • requires additional workspace for bellholes, spoil piles and sump(s) • ground vibrations and associated pressure waves could be an issue during sensitive life history phases for fish	• can be quick under the right conditions • avoids clean-up of bed and banks • cave-ins of borehole are unlikely • larger pipe diameters can be accommodated • may be able to construct during sensitive fisheries restricted activity windows	• can be slow under adverse conditions • potential bellhole cave-in ahead of ram • seepage into bellhole • with excessive seepage in course fluvial material it may be impossible to keep hole dry • specialized equipment may be required • potential corrosion problems from coating stripping • relatively inaccurate • limited to ~50 m in length • excessive borehole depth on deeply incised watercourses or watercourses with moderate or greater approach slopes	• fine-textured imper-meable soils • low water table • irrigation ditches • where streambed cannot be disturbed • can also be used in coarse-textured substrate • narrow to moderate watercourse (*i.e.,* <30 m) • where the watercourse is only slightly incised and approach slopes are absent or slight

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
TRENCHLESS iii) Horizontal Directional Drilling (see Dwg. 11)					
• slant drill used to drill under watercourse and, where practical, approach slopes	• no sediment release unless frac-out occurs • no bank disturbance • no streambed disturbance • may avoid approach slope disturbance • maintains normal streamflow • maintains fish passage • not likely to result in HADD • maintains vegetation buffer on both sides of watercourse	• disturbance of drilling and target area • disposal of drilling fluids • fractures in substrate may release pressurized drilling fluids into watercourse • circulating drilling fluid may wash out cavities under the watercourse and banks resulting in sinkholes • possible spills from drilling sump(s) down towards watercourse • large area may be required on floodplains	• eliminates clean-up and reclamation in between entry and exit points • avoids work in repairing and restoring banks • reduction in reclama-tion costs • reduction of long-term maintenance • may be able to construct during sensitive fisheries restricted activity windows • small diameter pipelines successfully drilled across sensitive watercourses or up steep slopes can be cost effective by reducing habitat compensation and reclamation costs	• moderately to very expensive • success depends on substrate • specialized equipment • slow construction / installation • limited to arc that can be drilled for pilot hole (10-20^{o} entry / exit angles) • limited arc that pipe can “rope” through the hole, especially large diameter pipe • may take several attempts • drill stem may get “stuck in the hole” and tools can get lost, especially on large diameter reams • no guarantees that drill will be successful • may damage coating / pipe	• watercourse with sensitive habitat where no instream activity allowed • watercourses where HADD may result from instream activity • areas with very unstable approach slopes • high aesthetic concerns (*i.e.,* parks) • restrict HDD staging in the floodplain, where conditions allow.

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	**Disadvantages**	**Advantages**	**Disadvantages**	
TRENCHLESS iv) Micro-tunneling					
• use a small tunnel boring machine to create a tunnel for the pipe or casing	• no sediment release • no bank disturbance • no streambed disturbance • no approach slope disturbance • maintains normal streamflow • maintains fish passage • not likely to result in HADD	• tunnel spoil / slurry requires large areas • disposal of tunnel spoil • large space require-ments on flood plains	• can be utilized in most substrates above or below the water table • eliminates clean-up and reclamation in streambed and banks • may be able to construct during sensitive fisheries restricted activity windows	• special equipment and crew are required • limited by length of pipe to be pushed and the friction forces imposed • high cost • may require detailed engineering • tunnel spoil / slurry may require removal or settling tanks and water treatment if chemical lubricants were used	• large diameter pipelines • crossings with ample room for tunnel spoil storage and bellholes • high aesthetic concerns (*i.e.,* parks)
AERIAL i) Bridge Attachment					
• attach pipeline to existing bridge struc-ture	• no sediment release • no bank disturbance • no streambed disturbance • maintains normal streamflow • maintains fish passage • not likely to result in HADD	• possible visual impact • safety and potential introduction of product into watercourse due to third party damage • potential introduction of paint and cleaning products into watercourse during future maintenance	• reduces clean-up and reclamation of bed and banks	• potentially expensive • depends on bridge design • specialized crew and equipment • slow construction / installation • potential for third party damage • regulatory approval may be delayed or denied • ongoing maintenance required	• large watercourse with sensitive habitat where no instream activity is allowed • areas with very unstable approach slopes • high aesthetic concerns (*e.g.,* parks) • where an existing bridge has been built • deep gorges / canyons • urban areas where bridges are abundant

Table 3.1 Pipeline Watercourse Crossing Construction Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
AERIAL ii) Self-Supporting Clear Span Bridge					
• construct bridge or abutments to carry pipeline	• no sediment release • no streambed disturbance • no bank disturbance • maintains normal streamflow • maintains fish passage • not likely to result in HADD	• visual impact • safety and introduction of product into watercourse due to third party damage • instream construction required for bridge abutments • may trigger additional regulatory review • may require removal of potential danger trees within riparian zone to maintain integrity	• reduces clean-up and reclamation of streambed and banks	• very expensive • specialized crew and equipment • slow construction / installation • potential for third party damage • regulatory approval may be delayed or denied • ongoing maintenance required • requires design to meet *Navigable Waters Protection Act* requirements	• large watercourse with sensitive habitat where no instream activity is allowed • areas with very unstable approach slopes • deep gorges / canyons

Table 3.2 Temporary Vehicle Watercourse Crossing Techniques

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
EXISTING BRIDGE					
• utilize existing bridge off right-of-way for access across watercourse	• no instream disturbance • no bank disturbance • no approach slope disturbance • maintains regular streamflow • maintains fish passage	• terrestrial disturbance caused by access to and from right-of-way via shoo-flies	• limited const-ruction costs • weight limit probably not an issue	• inefficient to drive around • complications of shuttling equipment • may slow process of construction	• where trenchless crossing methods are used • where crossings are near bridges • on larger rivers where other methods are not feasible • where sediment release is of concern • where streamflow and fish passage must be maintained
TEMPORARY BRIDGE (see Dwg. 12)					
• construct temporary bridge with native timber or import portable bridge	• limited stream disturbance • limited sediment release • maintains streamflow • maintains fish passage	• possible bank and app-roach slope disturbance • sediment release if bank abutments are built to support bridge • cap over timber bridge may cause sediment release in watercourse • may interfere with navigable use of waterway • sediment mobilization from scour if instream abutments are used for multiple bridge spans	• strong • removable • reusable (portable) • can be located at optimal location	• may entail a substantial amount of work to trans-port or construct bridge • moderate costs • specialized equipment / crew • timber bridge may require cap • timber bridge span is limited • regular maintenance and repair of erosion and sediment controls required	• small to moderate size watercourses with stable banks • larger watercourses may be crossed with multiple bridge spans and instream abutments • bridge must be maintained

Table 3.2 Temporary Vehicle Watercourse Crossing Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
ICE BRIDGE (see Dwg. 13)					
• construct bridge over ice on watercourse • remove snow and flood to strengthen if warranted	• limited sediment release • maintains streamflow • maintains fish passage	• susceptible to winter thaw • grading of banks and approach may be necessary • potential safety hazard • possible depression of ice and blockage of flow and fish passage in shallow watercourse • contamination of watercourse may result during thaw	• can be easily constructed where needed	• slow to construct • limited to freezing conditions • potential for thawing • safety concerns • ice must be >0.5 m thick • contingency required for thawing conditions • logs may be required for reinforcement • moderately expensive • must be maintained free of soil	• moderate to large sized watercourses with low approach slopes and banks • location where ice is thick and solid • relatively low velocity and deep watercourses • where sediment release is of concern • where streamflow and fish passage must be maintained • winter projects
SWAMP MATS					
• cabled logs, timbers or prefabricated steel pipes or rails in the form of a mat or grid • tie enough mats together to form crossing	• minimizes sediment release • mat surface less likely to embed into substrate • clean removal • generally maintains streamflow • can be used to span very narrow watercourses • can be used to protect banks where bridge spans are secured	• possible grading of banks required • could restrict flow and fish passage if watercourse is too shallow • introduction of wood/bark into streambed	• easy to install • easy to construct • easy to remove • portable • low cost, local materials • not prone to freezing into substrate	• logs deteriorate and break up with extensive use • susceptible to washout • not as stable as some other crossings • has to be shallow crossing <0.3 m • safety concerns due to instability	• small to moderate size shallow watercourse where disruption of substrate is a concern and ease of removal is important • where fish passage, streamflow and sediment release are not a concern

Table 3.2 Temporary Vehicle Watercourse Crossing Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
LOG / PIPE FILL					
• cable logs or pipes together and fill in channel • cap of snow often used • cable is wrapped around logs or pipes to ease removal	• limited sediment release • pipes maintain flow and may maintain fish passage if installed correctly • clean removal on solid substrate	• can sink into substrate • if they freeze in place, are hard to remove and may impede flow during spring run off • difficult removal may increase effects on bed and banks • small logs may block flow and fish passage	• low cost, local materials • easy to install • easy to construct • easy to remove when not frozen	• will freeze in during winter • difficult to remove • cap may be necessary and difficult to remove • prone to deterioration and break-up	• small steep banked creeks • may be used like corduroy on shallower creeks • where fish passage and flow are not a concern
SNOW FILL					
• plow clean snow into creek channel and pack • logs may be used for reinforcement	• limited sediment release • minimizes bank disturbance	• introduction of soil into snowfill may lead to sediment release during spring break-up • some deterioration of banks may occur • may block flow and fish passage if no ice in watercourse	• low cost • easy to construct • easy to remove • use of local material • only have to be notched open rather than removed to facilitate flow during spring run off	• deteriorates with use • high maintenance • susceptible to thaw • logs may be needed for reinforcement • must be removed prior to spring break-up	• small watercourse in winter where fish passage and streamflow are not a concern • most appropriate for small intermittent drainages • winter project • not practical when snow depth is limited
RAMP AND CULVERT / FLUME (see Dwg. 14)					
• divert flow through culvert laid perpendi-cular to pipeline • use steel pipe not galvanized culvert for flume • build ramp over top	• limited sediment release • maintains stream flow and fish passage • bottomless arch culverts can be used where fish habitat/passage is a concern	• sediment release when filling around culvert and removing culvert • susceptible to washout • icing in winter may block flow and fish passage • may require bank grading	• when used in combination with flume const-ruction tech-nique, flume replaces culvert • forms one dam for dam and pump	• heavy traffic may crush culvert • susceptible to washout • may require specialized materials such as sandbags and select fill	• small to moderate sized watercourses with or without flow • where streamflow and fish passage are of concern • commonly used • watercourses with defined channel and banks

Table 3.2 Temporary Vehicle Watercourse Crossing Techniques, Cont'd

Description	Environmental Considerations		Construction / Engineering Considerations		Comments
	Advantages	Disadvantages	Advantages	Disadvantages	
FORD (see Dwg. 15)					
• drive equipment across streambed	• no instream construction • maintains streamflow and fish passage	• high potential for sediment release depending on substrate • rutting of streambed • requires grading of banks • possible sediment release during grading of banks	• fast • easy • can be located in many places • inexpensive	• watercourse depth is a limitation • vehicles may get stuck • streambed may not be level and may require gravelling or construction of a travel pad (see below)	• coarse-textured substrate • all sizes of shallow watercourses • where sediment release is not a concern • where fish passage needs to be maintained
TRAVEL PAD					
• construct rockfill ford below surface of watercourse • a modified ford crossing	• maintains streamflow and fish passage	• large amount of sediment release during construction and removal • each pass of a vehicle creates sediment release • requires bank grading • may be a barrier to fish if poorly designed • may act as a weir and flood upstream areas	• easy to build • can be placed in most locations • levels out uneven bottom	• potentially expensive • difficult to remove • requires 20 cm (minimum) of water flow to maintain fish passage • may require select material to be imported	• all sizes of shallow watercourses • where sediment release is not a primary concern • useful on wide shallow rivers where no bridges are available • used with cobble sized fill, preferably clean (no fines)
BARGE					
• construct or import barge to carry equipment across watercourse	• no instream construction • no sediment release • maintains streamflow and fish passage	• banks require grading or a loading ramp may be required • may require special restrictions and mitigation for fuel transport	• may be used in conjunction with crossing construction from barge	• may be difficult to obtain or build • slow if multiple shuttles are required • expensive • requires sufficient depth to float barge • specialized equipment • inaccessible in some regions	• large, deep water crossings, generally proximal to urban centres • large, deep water crossings where no alternative form of summer access is available, *e.g.,* northern Canadian rivers

Adapted from Mutrie and Scott 1984

4 Risk-based Watercourse Crossing Selection Process

The success of a pipeline associated watercourse crossing depends upon the selection of an appropriate crossing method to prevent or reduce the adverse environmental effects of crossing construction. The following subsections identify issues and risks that proponents may wish to consider, to assist them in the selection of appropriate water crossing techniques. Since this document is intended to be general in nature, the exact technique and protection measures implemented during a watercourse crossing may vary according to the specific requirements of the project and site-specific conditions at the water crossing.

When highly sensitive or high profile watercourse crossings are anticipated to be a component of a proposed project, it is important that government agencies' representatives and the public be contacted during the initial stages of route and crossing selection. Once established, ongoing feedback between the proponent and the agencies will clarify the concerns and facilitate approvals.

Planning a pipeline watercourse crossing project involves many steps, from route selection to post-construction monitoring. There are several points in the planning process where the details of the proposed project will require it to proceed along a specific regulatory course. Figure 4.1 outlines the key steps in planning watercourse crossing construction projects.

4.1 DFO Risk Management Framework

DFO has established a national Risk Management Framework (RMF) to provide consistency to the determination of potential effects of development projects, including pipeline associated watercourse crossings, on fish and fish habitat. This nationally standardized approach to managing risk allows DFO biologists, partner agencies and proponents to determine what fish habitat concerns are associated with a project, develop appropriate mitigation to address anticipated effects and assess the risk of residual negative effects to fish habitat.

The RMF consists of a Pathways of Effects (POE) model used to determine the potential effects on fish habitat resulting from a work, and a Risk Determination Matrix (Figure 4.2) that incorporates the scale of any residual negative effects and the sensitivity of the specific fish and fish habitat to make a determination of the appropriate regulatory approach. The POE model is a tool used to list the predicted effects on fish and fish habitat caused by specified land- and water-based construction activities. If the POE model identifies any residual negative effects caused by a proposed project that cannot be fully mitigated, then these effects are examined by DFO in the context of the Risk Determination Matrix.

4.1.1 Elements of a Risk Management Program

A risk management program, including the DFO RMF, is composed of three principal parts:

- **risk communication**: description of the elements of risk using common language
- **risk assessment**: determination of the nature and probability of the elements of risk
- **risk management actions**: measures taken to reduce risk to the lowest practical level

Comprehensively managing the environmental risk of a crossing project must include all of the above elements. It is important that the steps taken to communicate, assess and manage risk are well documented.

4.1.2 Process for Assessing Risk to Fish Habitat

The process for assessing the risk to fish habitat posed by a crossing project involves several proponent-directed steps and a final risk evaluation and decision by DFO biologists (Figure 4.3). The proponent must first determine whether the crossing is located in fish habitat that directly or indirectly supports a fishery or has the potential to support a fishery, and whether an operational statement (OS) applies to the proposed crossing method. These OSs specify the crossing method, habitat characteristics and mitigation and monitoring measures under which the project may proceed without further DFO review. If no OS is in force for the proposed crossing project, then the proponent determines the potential effects on fish habitat using the POE model and designs mitigation measures to break the identified pathways.

In the next step of the risk assessment, DFO biologists evaluate the certainty associated with the proposed mitigation measures and the direction (positive, neutral or negative) of any residual effects. If negative residual effects exist, then DFO will use the Risk Determination Matrix to determine the appropriate management approach, which could include an authorization to commit HADD under Section 35 of the *Fisheries Act*. Such authorization may or may not be granted, or may be subject to habitat compensation conditions, depending on where on the Risk Determination Matrix (Figure 4.2) the residual effects fall.

Certainty Associated with Mitigation Measures

In order to determine if the crossing project design, as proposed, is adequate to avoid any negative residual effects on fish and fish habitat, the certainty associated with the proposed mitigation measures will be evaluated by DFO biologists. There are two key factors that are considered when evaluating the level of certainty:

- **effectiveness of proposed mitigation**: many mitigation measures are standard industry practice and have been employed by proponents and contractors for many years and have been proven to be effective. Other innovative mitigation measures can be used in a risk-based approach, however, the uncertainty associated with their effectiveness must be assessed and contingency plans put in place in case of failure.
- **knowledge base of effects**: in some cases the effects of a project on fish and fish habitat are well understood and can be accurately predicted. In other cases, the effects are much less understood and mitigation and contingency planning must acknowledge this knowledge gap.

It is important to note that even a moderate level of uncertainty does not mean that the project cannot proceed. Rather, monitoring, contingency planning and thresholds past which work cannot continue must be considered and incorporated by the proponent into the project design and/or by DFO into the project authorization.

Scale of Negative Residual Effects on Fish and Fish Habitat

A negative effect on habitat may not necessarily be high risk. Some negative effects may be of such short duration, limited spatial extent or small magnitude that they are still considered to be low risk. Examination of the attributes of negative effects permits a qualitative determination of the scale of risk associated with them. These attributes include:

- **intensity**: the amount of change from the baseline conditions that is expected. This attribute is usually considered in the context of quantitative, measurable parameters (*e.g.*, temperature, flow, water quality measures)
- **spatial extent**: the geographic size of the anticipated effect, including zone of influence downstream
- **duration**: the expected duration of the effect, from some lasting only minutes to other effects causing permanent change
- **reversibility**: the likelihood that the effect will reverse as the system re-achieves equilibrium
- **timing**: the time of the year at which the effect takes place. For example, effects during critical spawning windows have a larger scale of negative effect
- **extreme events**: unlikely, but extreme, events may be associated with a negative effect. Such extreme events may be caused by severe weather, failure of mitigation or accidents and malfunctions. The probability and severity of potential extreme events must be considered

An evaluation of the combination of all of these attributes will determine the placement of a negative effect on the y-axis (scale of effect) of the DFO Risk Determination Matrix (Figure 4.2).

Sensitivity of Fish and Fish Habitat at Crossing Location

The second factor in the determination of the overall risk of a negative effect is the sensitivity of the fish and their habitat at the location of the proposed crossing project and within its zone of influence. This factor is of importance as the overall risk of a negative effect of moderate scale will be greater in a habitat or fish community of higher sensitivity. The categorization of the sensitivity of fish habitat includes the following attributes:

- **species**: the species of fish present at a crossing location and in the zone of influence will vary their sensitivity to disturbance
- **flow**: ephemeral systems that only contain water for a short duration after a rainfall event are less sensitive than perennial systems that always contain water
- **thermal regime**: cold water systems are more sensitive to perturbations than warm water systems
- **use of habitat**: spawning and rearing habitats are more sensitive than migratory corridors, although interruption of corridors may diminish the production of fish

An evaluation of the combination of all of these attributes will determine the placement of a crossing location and its zone of influence on the x-axis (habitat sensitivity) of the DFO Risk Determination Matrix (Figure 4.2). Several of the attributes should be rated high for a habitat to be considered to be highly sensitive.

Residual Effects and the Risk Matrix

The Risk Determination Matrix (Figure 4.2) allows proponents and DFO biologists to qualitatively determine what level of DFO management involvement should be applied to a proposed project. The scale of the effect and the sensitivity of the affected habitat, as described above, define where a negative effect falls on the matrix. This approach also guides a proponent's communication with DFO in determining whether an authorization, notification or no contact is required for a particular crossing project.

The levels of management intervention by DFO, in increasing order, are:

- **no risk crossing**: no *Fisheries Act* requirements nor contact with DFO
- **low risk crossing**: follow available OSs and best management practices, submit notification to DFO
- **medium risk crossing**: streamlined authorization process, regulations and class authorizations, letter of advice may be issued

- **high risk crossing**: site specific DFO review and *Fisheries Act* authorization required, habitat compensation if residual negative effects
- **significant negative effects**: activity not permitted without intensive DFO consultation and habitat compensation measures, project approval questionable

Role of Operational Statements in Project Review

DFO biologists spend a great deal of time reviewing project proposals for which there is low or no risk to fish and fish habitat. In order to increase regulatory efficiency, DFO has started to produce OSs for low and no risk works that allow, under specific conditions, proponents to proceed with projects without DFO advice or approval. These OSs specify the crossing method, habitat characteristics and mitigation and monitoring measures under which the project may proceed without DFO review. The most current OSs available in the region where the project is to be constructed should be consulted to determine DFO management intervention.

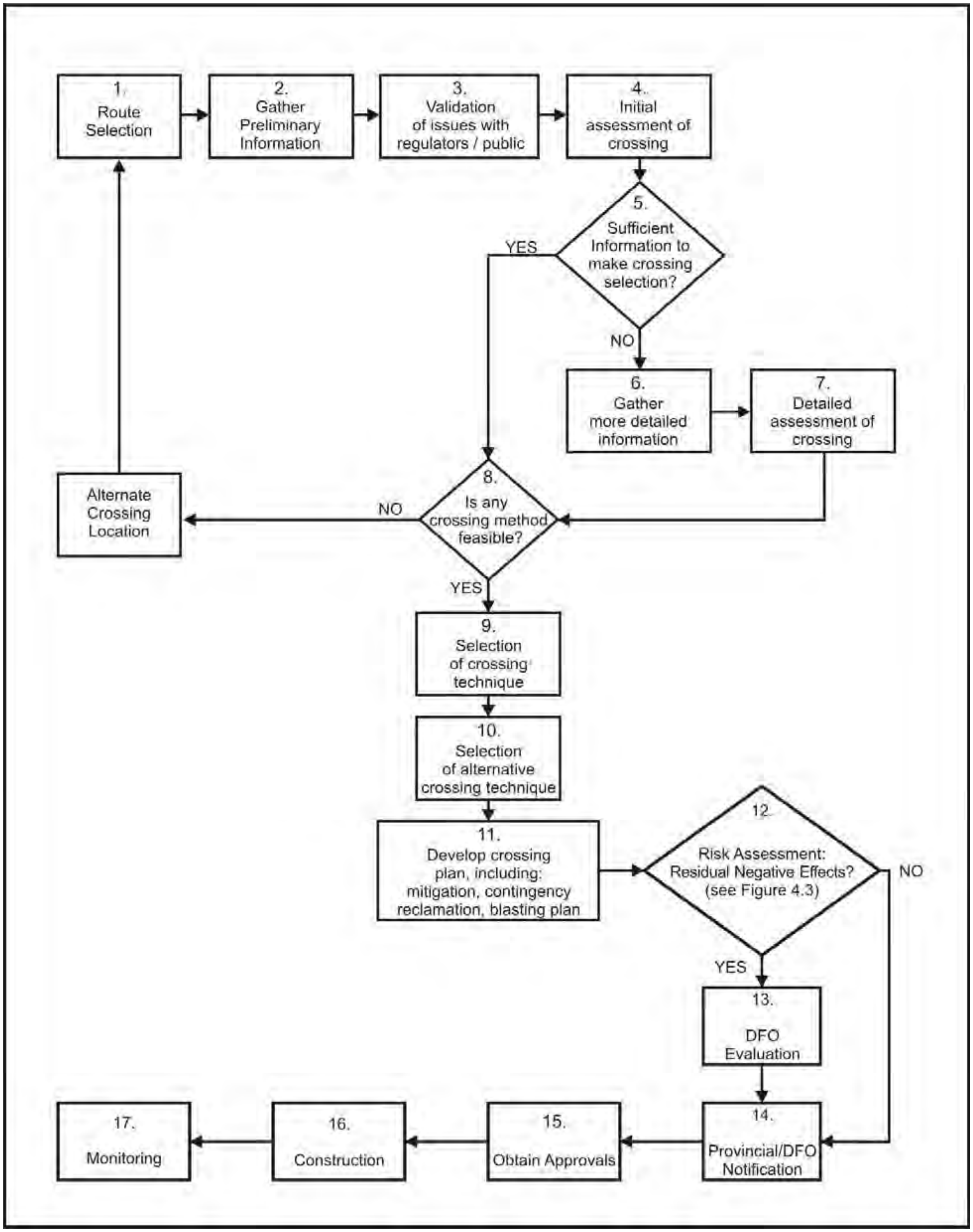

Figure 4.1 Planning Summary for Watercourse Crossings

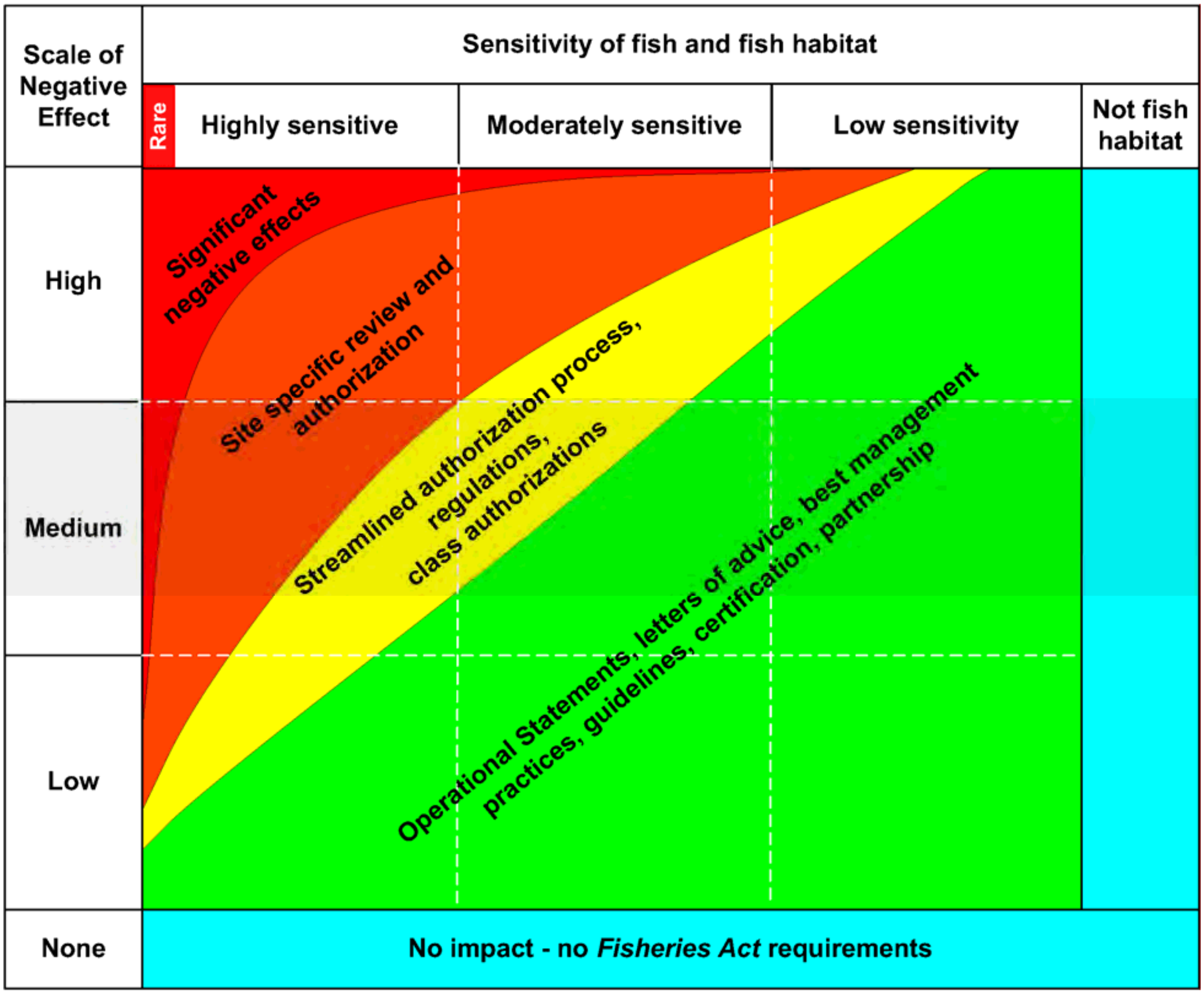

Figure 4.2 DFO Risk Determination Matrix

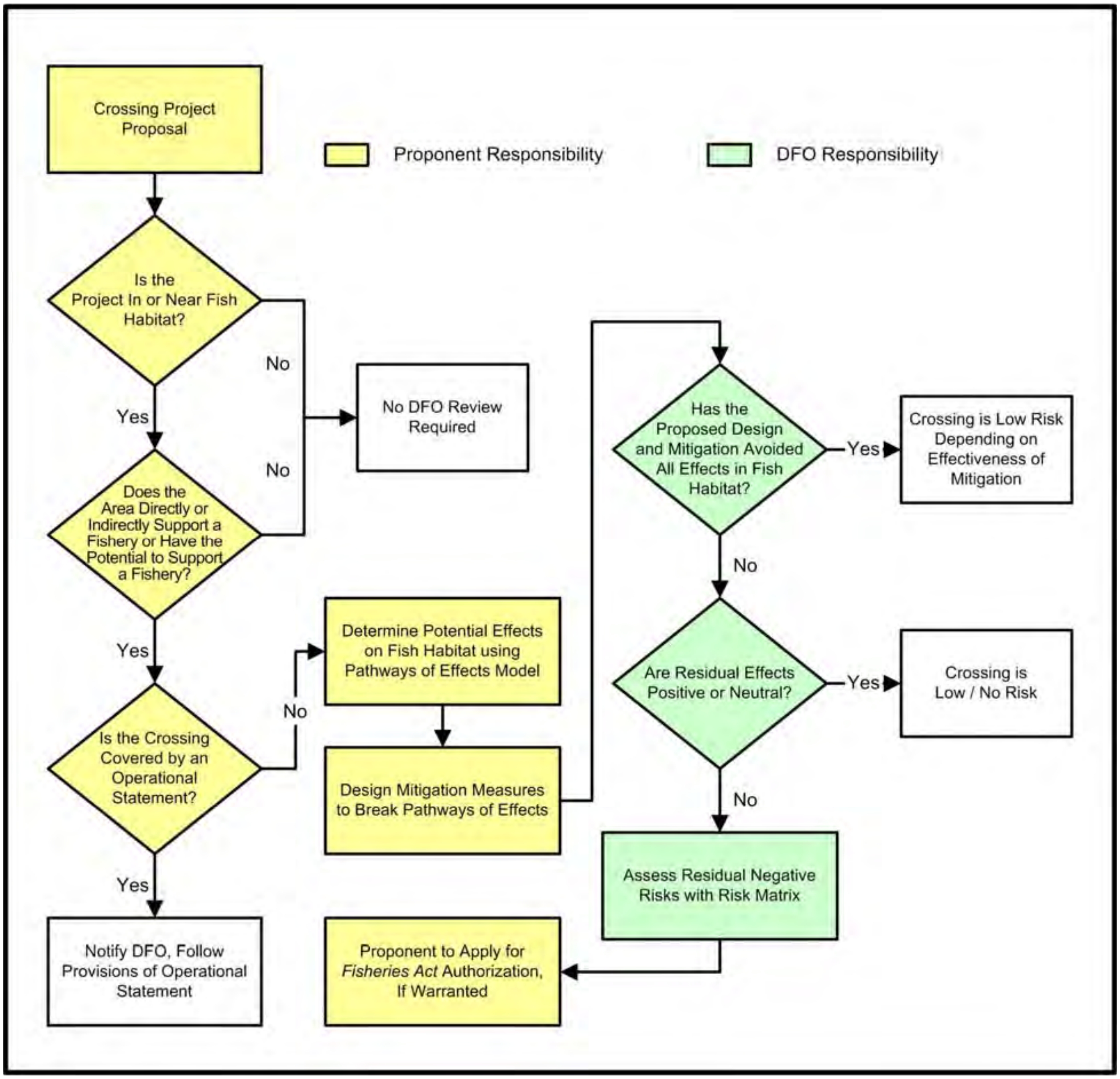

Figure 4.3 Process for Assessing Risk to Fish Habitat

4.2 Crossing Assessment

A site-specific environmental evaluation may be required where there are insufficient available data to adequately assess the risks associated with a crossing. **Table 4.1** summarizes the general environmental considerations to be evaluated during an assessment.

4.2.1 Aquatic Assessment

The primary objective of the aquatic assessment is to identify the level of sensitivity of the watercourse and aquatic resources, and to gather information for routing and crossing method selection, and development of mitigation measures.

In most cases, routine pipeline crossings of watercourses with known sensitivity do not require aquatic assessments since standardized mitigation as outlined in Section 5.0 designed to protect the aquatic resources is implemented during construction. In other situations, where little information is known relative to the sensitivity, further investigations are required.

The level of detail for these investigations will vary according to the watercourse and the construction techniques considered. Where crossing construction will not generally result in HADD of fish habitat (*i.e.*, reaches with limited habitat potential), field data collection should be limited to basic fish habitat information including: type of fish habitat (warmwater or coldwater), common fish species; and a general description of any fish habitat at the proposed crossing and within the zone of influence.

Where little information is available on a specific watercourse, yet regional information and initial routing investigations indicate that the watercourse may support sensitive or critical habitat, a more detailed aquatic assessment may be warranted. **Table 4.2** presents a comprehensive list of parameters that could be evaluated. Generally, most watercourse assessments would include some, but not all those listed. Nevertheless, the greater the detail the more likely that the regulatory authorities will review and approve the crossing without delays caused by further field visits or additional meetings. Prior to conducting any assessments, proponents should discuss the level of detail required with regulatory agencies, at which time they may suggest the type of information and assessment requirements.

Table 4.1 Environmental and Engineering Considerations for Pipeline Crossing Selection

Considerations	Details
Geotechnical / Hydraulic	- depth of bedrock - stability of bedrock - contaminated substrates - slope stability - bank stability - bank height - watercourse discharge, velocities and roughness - channel depths/widths/slope/cross section - flood and low flow prediction/discharges - bank and substrate composition and stability - abandoned channels/flood plains - areas of scour, erosion and deposition - reach morphology - sediment transport potential - flow variation - water quality changes/depth of groundwater - future channel migrations - ice conditions
Soils	- general soil composition - chemical contamination - reclamation suitability
Vegetation	- rare and endangered species - existing disturbance at crossing
Fish and Wildlife	- fish species present - rare and endangered species - existing aquatic and terrestrial habitat - sensitive periods and timing constraints - spawning areas - nursery/rearing areas - fish overwintering areas - fish migration - wildlife overwintering areas - sensitivity of watercourse - existing barriers to fish migration - existing disturbance at crossing
Land Uses	- existing rights-of-way - aesthetics - navigation - recreational, domestic and commercial fishery - First Nations' traditional land use - historical, palaeontological and archaeological resources
Downstream Water Users	- licensed water use - domestic and municipal water supply - irrigation/drainage - water quality changes (appearance, odour, taste, chemical contamination)
Cumulative Effects	- barriers to fish migration - number of adjacent watercourse crossings - number of watercourse crossings and barriers in watershed - total existing riparian clearing in watershed - total existing road network in watershed - public right-of-way use - need for access management - operation and maintenance requirements

Table 4.2 Detailed Aquatic Assessment Evaluation Parameters

General Characteristics
Name of Watercourse
Kilometre Post
Legal Land Location
Topographic Map No.
UTM Coordinates
Watercourse Length Inspected Upstream (m)
Watercourse Length Inspected Downstream (m)
General Terrain Setting
Floodplain Material
Watercourse Navigability
Photographs of Banks and Channel
General Watercourse Characteristics
Mean Wetted Channel Width (m)
Mean Bank Full Width (m)
Depth of Pool / Run / Riffle (m)
General Streambed Characteristics
Parent Streambed Material
Bank and Channel Widths
Bank Material Characterization
Organics (%)
Clay (%)
Silt (%)
Sand (%) (<0.2 cm)
Gravel (%) (0.2 - 8 cm)
Cobble (%) (8 - 25 cm)
Boulder (%) (>25 cm)
Bedrock (%)
Channel Characteristics
Location of Thalweg
Stream Confinement
Channel Cross Section
Side Channel (%)
Streambed Gradient (%)
Turbulence
Natural Drop Offs
Evidence of Bedrock Outcrops

Land Use / Access
Land Use
Access
Recommended Work Side
Waterflow
General Flow Characteristics
Velocity (m/s)
Discharge (m^3/s)
Stage
Bank Characterization
Bank Stability
Bank Height (m)
Bank Slope (%)
Approach Slope (%)
% of Bank with Riparian Vegetation
% of Bank With Overhanging Vegetation
% of Bank With Undercut
Dominant Riparian Plant Species
Substrate Characterization
Bedrock (%)
Boulder (%) (>25 cm)
Cobble (%) (8 - 25 cm)
Gravel (%) (0.2 - 8 cm)
Sand (%) (<0.2 cm)
Silt (%)
Clay (%)
Detritus Present
Water Quality
Temperature (°C)
pH
Conductivity (μs/cm)
Dissolved Oxygen (mg/L)
Total Suspended Solid (NTU)
Turbidity

Table 4.3 Detailed Aquatic Assessment Evaluation Parameters Cont'd

Habitat Features
Fish Habitat Potential and Habitat Features
Aquatic Macrophytes
Algae
Natural Barriers to Fish Movement
Artificial Barriers to Fish Movement
Fish Captured
Species
Number
Fork Length
Life Phase
Erosion
Bank Erosion Potential
Evidence of Slumping on Banks
Evidence of Slumping on Approach Slopes
Evidence of Gullying
Other Erosion Features
Scour Potential
Bed Erosional Potential
Relative Sediment Transport Potential
Relative Suspended Solids Load
Groundwater Seepage

Fish Sampling Results Summary
Fish Collection Card
Fish Reported in the Watercourse
Electrofishing(s)
Gill Netting (panel length x time)
Seining (net length x hauls)
Minnow Trap (number of traps x time)
Available Overhead Cover %
Percentage of Total Overhead Cover
Large Organic Debris
Undercut Bank
Overhanging Trees
Overhanging Shrubs
Overhanging Grass
Available Instream Cover %
Percentage of Total Instream Cover
Pool
Large Organic Debris
Boulder
Instream Vegetation
Turbidity

Sources: Adapted from RIC (1999) and Alberta Transportation (2001).

Note: These parameters should be considered as a very comprehensive list and not those that should be used in all assessments. Aquatic assessments should be tailored to the size and sensitivity of the watercourse. This list should be used as a guideline from which to select those parameters that are appropriate for the size and sensitivity of the watercourse.

4.2.2 Geotechnical and Hydraulic Assessment

The objective of a geotechnical and hydraulic assessment is to identify long- and short-term processes that could affect habitat and water quality as well as the presence of potential hazards that may threaten the integrity of a pipeline and, to a lesser extent, vehicle crossing. In addition, a detailed geotechnical evaluation of subsurface conditions may be required for trenchless techniques (*e.g.,* horizontal directional drill).

Depending on the local conditions, the geotechnical and hydraulic assessment should include:

- river hydrology;
- geology of the approach slopes, bed and banks;
- drainage control on the approach slopes;
- slope stability; and
- bed scour.

In some cases it may be advisable to also consider surficial and fluvial materials.

River hydrology should be evaluated to identify the discharges that could be encountered during the period of construction and the potential discharges that could be encountered during a flood. Other streamflow information indicating which periods would not be suitable for construction should also be included.

The geology and surficial geology of the approach slopes, bed and banks of the watercourse should be identified and evaluated. Information on the type of substrate material aids in the determining of construction techniques, requirements for blasting and the potential for the introduction of sediment into the watercourse. The bank and approach slope geology analysis is used in establishing the stability of the slopes and in evaluating the likelihood of major channel migrations.

A geotechnical engineer should design detailed drainage and sediment control for approach slopes. Examination of the approach slopes and textural classes of soils in the valley aids in the positioning of subdrains, trench breakers, silt fences, netting, cross ditches and diversion berms.

Before planning trenchless techniques, surficial and fluvial materials within the drill or bore path should be evaluated to determine whether they are appropriate for this method. Common techniques include ground penetrating radar (GPR) and drilling of bore holes.

4.2.3 Cumulative Effects

Watercourse crossings often contribute to cumulative effects on fish and fish habitat, wildlife and wildlife habitat and land and resource use. Planners and engineers should be aware of the issues, timing restrictions, mitigation measures, and possible regulatory requirements for assessing and managing cumulative effects.

Cumulative effects evaluations consider the combined effects now known to take place over larger study areas and longer time frames. Cumulative effects must be specifically considered for all individual watercourse crossings where HADD authorizations are required and for all NEB-regulated projects (see Section 2.1.4 of this report). Unlike aquatic assessments that focus on sensitivity and risk during the construction period, the primary objective of cumulative effects analysis is to identify and mitigate long-term effects on fish and wildlife mortality, movements, and maintenance of habitat availability and quality. This recognizes that watercourse crossings and rights-of-way have an ‘indirect footprint’ that extends well beyond the physical footprint until native vegetation on and immediately adjacent to the right-of-way returns to pre-disturbance conditions. This generally requires decades to achieve.

In recent watercourse crossing applications, some projects have been required to assess the wildlife and vegetation resources of valleys associated with the watercourse. In particular, some jurisdictions pay special attention to overwintering ungulates (*i.e.,* moose, deer, elk), species with special conservation status (*e.g., Species At Risk Act* or the Committee on the Status of Endangered Wildlife in Canada (COSEWIC) listed species, provincially listed species or migratory birds) or special status vascular plants (*e.g., Species At Risk Act* or COSEWIC listed species or provincially listed species).

Cumulative effect assessment is an evolving practice and no standard accepted method exists for watercourse crossings. The level of effort should be appropriate to the number of crossings being considered, other existing watershed disturbances, and the combined long-term risk to fish and fish habitat. One of the key deficiencies of current approaches is that they typically overlook the long-term cumulative effects risk from: increased harvest; movement barriers (*e.g.,* culverts); and non-point sediment, nutrient, and contaminant input.

A detailed discussion of analysis tools is beyond the scope of this document, however proponents and technical specialists should choose the most appropriate approach from the suite of tools described in **Table 4.4**. Additional information is provided in the *Filing Manual* (NEB 2004) and Hegmann *et al.* (1999).

Table 4.4 Cumulative Effects Analysis Tools for Watercourse Crossings

Approach	Description	Advantages	Disadvantages
Qualitative	• Descriptive evaluation of potential cumulative effects associated with aquatic and terrestrial POE. Should consider construction and operations phases and entire watershed(s).	• Lowest cost and time requirements. • POE can be explicitly discussed.	• Analysis generally not systematic and transparent, increasing long-term risk to fish and fish habitat. • Effects of increased access and mortality (the proximate cause of most cumulative effects) generally not considered.
Species or Habitat Models	• Habitat-based models used to evaluate potential project-specific and cumulative effects on species or habitats of ecological, social, or economic importance (*e.g.,* evaluate loss of brook trout spawning, rearing, and overwintering habitat).	• Based on accepted impact assessment methods that consider habitat loss, the ultimate cause of cumulative effects. • Able to quantify species- and site-specific habitat loss or alteration requiring mitigation or compensation. • DFO guidance documents exist (*e.g.,* Ford *et al.* 1995; Minns 1995, 1997; Minns *et al.* 1995, 1996; Portt *et al.* 1999).	• High cost and time requirements. • Independent analyses of different species or habitats makes direct comparison of trade-offs difficult. • Generally underestimates long-term cumulative effects risk because all POE can not be explicitly considered (*e.g.,* habitat-based approaches generally overlook mortality risk, barriers, and chronic non-point effects; Warren and Pardew 1998; Angermeier *et al.* 2004).
Watershed Evaluations	• Calculate numerical measures of watershed or landscape conditions to evaluate incremental and cumulative effects risk (*e.g.,* determine stream crossing density or area of roads within riparian corridors; IWAP 1999).	• Medium cost and time requirements. • Provides quick test to determine if project modifications or more detailed assessment are necessary. • Best able to document project contribution to long-term cumulative effects risk.	• Does not quantify species-specific habitat loss or alteration. • Value of mitigation strategies may not be quantifiable because underlying mechanisms can differ.
Integrated Evaluations	• Combine habitat-based models with watershed evaluations to consider how local effects contribute to long-term watershed effects.	• Combined benefits of both approaches.	• Highest cost and time requirements; generally only done for very large or contentious projects or for watershed restoration. • Complex.

4.3 Environmental Selection Considerations

Selection and approval of watercourse crossings by the proponent and regulators, respectively, requires a thorough knowledge of the advantages and disadvantages of various crossing methods and techniques. Unfortunately, except for a few senior field personnel, most engineers, planners and regulatory staff do not attain sufficient experience to understand the various techniques to be able to sufficiently evaluate the risks of each. Tables 3.1 and 3.2 summarize the engineering and environmental advantages and disadvantages of the various techniques discussed in this document.

TERA Environmental Consultants (1996) and P.A. Harder and Associates Ltd. (1995) summarized a total of 326 pipeline associated watercourse crossing case histories as background documents to this document (Appendix B). These studies, although largely anecdotal, do portray a good cross section of both successful and poorly constructed crossings.

In summary, unsuccessful watercourse crossing projects had the following problems:

- poor planning;
- no contingency planning;
- selection of an inappropriate construction technique for the conditions experienced during construction;
- inexperienced construction crews and inspectors;
- overestimation by the contractor of his ability;
- underestimation of the energy of a watercourse;
- insufficient quantity and size of equipment onsite;
- inadequate knowledge of the flows and subsurface conditions; and
- unforeseen/unanticipated circumstances.

Risk associated with the environmental aspects of a project can generally be divided into three types: regulatory risk; construction risk; and post-construction risk.

4.3.1 Regulatory Risk

Risks associated with not fulfilling the regulatory requirements during a crossing may be twofold. Firstly, the project may be delayed or rejected if no or insufficient information is submitted. In the event that an application is approved, insufficient information may cause the regulatory agency to invoke restrictive conditions to ensure protection of the resources. Secondly, if a project proceeds without the appropriate approvals, shut downs, charges and potentially convictions may result.

In a regulatory climate in which more emphasis is being placed on codes of practice, OSs and other increasingly independent regulatory tools, industry can expect that any violation of the regulatory requirements may result in more rigid interpretation of the legislation. Therefore, it is imperative that all permits and approvals are obtained and associated approval/permit/code of practice conditions are implemented to ensure compliance.

4.3.2 Construction Risk

Each technique has its own risks, some for which it is very difficult to plan and others for which there is little that can be done once a problem has arisen. Selecting and approving crossing techniques must be done with a full knowledge of the risks and proponents and regulators should recognize the adverse effects that can occur. The risks associated with each technique will vary according to many factors. This includes but is not limited to: project scope; contractor's ability, experience and commitment; pipe size; and season of construction.

Table 4.5 summarizes some of the more common problems associated with various techniques and identifies the environmental risks associated with each. In addition, it gives an indication of the scale of the identified risks as well as general mitigation measures and contingency plans that should be considered in advance of construction during the planning phase.

4.3.3 Post-Construction Risk

Proponents evaluate the short-term risks associated with various crossing techniques, but may not consider some of the longer-term, life-cycle factors. The following considerations should also factor into the planning and crossing design:

- long-term stability of slopes, streambanks and approach slopes;
- erosion and sedimentation;
- maintenance;
- pipeline integrity;
- monitoring;
- ongoing use of the right-of-way by off highway terrain vehicles; and
- other land uses.

In many situations, the long-term implications of operating a pipeline in a particular location may strongly affect the decisions regarding crossing technique, construction methods and reclamation.

Table 4.5 Risk Considerations for Watercourse Crossing Methods

Selected Potential Problems[1]	Environmental Risk(s)	Scale of Risk[2]	Mitigation and/or Contingency Plan(s)
OPEN TRENCHED: Plow, Bucket Wheel Trencher			
Unexpected extended periods in watercourse	Prolonged sediment load and deposition	Medium	Work through the night, ensure approvals are in place for extended periods, utilize larger and more equipment
Erosion of instream spoil storage	Prolonged sediment load and deposition	Medium	Ferry as much spoil to shore as practical
Equipment too small and prolonged instream activity	Prolonged sediment load and deposition	Medium	Bring in larger and more equipment
Fine textured substrate	Increased suspended solids introduced into water column during trench, backfilling and from spoil storage area	High	Prepare a sediment control plan in advance
Loss of ditch as a result of unstable bed materials	Prolonged sediment load and deposition	High	Work through the night, ensure approvals are in place for extended periods, obtain larger and more equipment
OPEN TRENCHED: Hoe			
Unexpected extended periods in watercourse	Prolonged sediment load and deposition	Medium	Work through the night, ensure approvals are in place for extended periods, utilize larger and more equipment
Erosion of instream spoil storage	Prolonged sediment load and deposition	Medium	Ferry as much spoil to shore as practical
Equipment too small and prolonged instream activity	Prolonged sediment load and deposition	Medium	Bring in larger and more equipment
Fine textured substrate	Increased suspended solids introduced into water column during trench, backfilling and from spoil storage area	High	Prepare a sediment control plan in advance
Loss of ditch as a result of unstable bed materials	Prolonged sediment load and deposition	High	Work through the night, ensure approvals are in place for extended periods, obtain larger and more equipment
OPEN TRENCHED: Dragline			
Equipment failures	Prolonged sediment load and deposition	Medium	Ensure sufficient back-up equipment is available
Unexpected extended periods in watercourse	Prolonged sediment load and deposition	Medium	Work through the night, ensure approvals are in place for extended periods, utilize larger and more equipment
Fine textured substrate	Increased suspended solids introduced into water column during trench, backfilling and from spoil storage area	High	Prepare a sediment control plan in advance, ensure approvals are in place for alternate crossing (*i.e.,* isolated)
Loss of ditch as a result of unstable bed material	Prolonged sediment load and deposition	High	Work through the night, ensure approvals are in place for extended periods, utilize larger and more equipment
OPEN TRENCHED: Dredging			
Unexpected extended periods in watercourse	Prolonged sediment load and deposition	Medium	Work through the night, ensure approvals are in place for extended periods, utilize larger and more equipment
Loss of ditch as a result of unstable bed materials	Prolonged sediment load and deposition	High	Work through the night, ensure approvals are in place for extended periods, utilize larger and more equipment

Table 4.5 Risk Considerations for Watercourse Crossing Methods, Cont'd

Selected Potential Problems[1]	Environmental Risk(s)	Scale of Risk[2]	Mitigation and/or Contingency Plan(s)
ISOLATED: Flume			
Leaking dam or flange	Increased water pumping and disposal concerns, flooding of work area and washout of dam	High	Ensure there are sufficient materials on hand to keep dams and flanges sealed
Flume may be of insufficient diameter	Uncontrolled flow through isolated area	High	Ensure that flume is sized to at least 150% of maximum anticipated flows and pumps are on standby to assist in a partial bypass
Flume is too long, straight or large for reach or watercourse	Undue disturbance to riparian habitat, banks and bed	High	Consider switching to an alternative technique Ensure flume is properly sized
Ditch water disposal problem	Water pumped onto land flows back to the watercourse	Medium	Have additional stand by pumps on hand and identify suitable settling ponds/sumps
Icing of flume pipe in winter	Work area flooding	High	Have additional stand by pumps on hand and identify suitable settling ponds/sumps
Flume may be of insufficient length and/or ditch excavation becomes too wide and threatens flume installation	Increased suspended solids introduced into water column in the event of a flume collapse	High	Have additional standby pumps at hand to assist in a partial bypass Consider switching to alternative technique or properly sized flume
Approaches too steep to thread bends in pipe under flume	Excessive grading, reclamation and bank restoration	Medium	Replace flume with high volume pumps or dam and pump to allow easier lowering in of pipe
Groundwater seepage into work area	Increased water pumping and disposal concerns	Medium	Have additional stand by pumps at hand and identify suitable settling areas
ISOLATED: Dam & Pump			
Dam poorly sealed	Increased water pumping and disposal concerns, potential washout of dam and flooded work area	High	Ensure there are sufficient materials at hand to keep dams sealed
Insufficient pump capacity (by design or icing of pump hose)	Work area flooding and increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
Pump malfunctions	Work area flooding and increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand
Dam topped or washed out	Increased suspended solids introduced into water column in the event of a collapse	High	Have additional stand by pumps and hoses at hand and identify suitable settling areas
Ditch water disposal problems	Water pumped onto land flows back to the watercourse	Medium	Have additional standby pumps and hoses on hand and identify suitable settling ponds/sumps
Groundwater seepage into work area	Increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
ISOLATED: High Volume Pump (Sump and Pump)			
Pump malfunctions	Work area flooding and increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand
Insufficient pump capacity (by design or icing of pump hose)	Work area flooding and increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas

Table 4.5 Risk Considerations for Watercourse Crossing Methods, Cont'd

Selected Potential Problems[1]	Environmental Risk(s)	Scale of Risk[2]	Mitigation and/or Contingency Plan(s)
Ditch water disposal problems	Increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
Groundwater seepage into work area	Increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
ISOLATED: Coffer Dam			
Ditch water disposal problems	Water pumped onto land flows back to the watercourse	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
Groundwater seepage into work area	Increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
Insufficient pump capacity (by design or icing of pump hose)	Work area flooding and increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand and identify suitable settling areas
Pump malfunctions	Work area flooding and increased water pumping and disposal concerns	Medium	Have additional stand by pumps and hoses at hand
Dam poorly sealed	Increased water pumping and disposal concerns, potential washout of dam and flooded work area	High	Ensure there are sufficient materials at hand to keep dams sealed
Dam failure	Work area flooding, increased suspended solids introduced into water column and safety	High	Have additional dam building materials at hand (*i.e.,* median barriers and water-filled dams)
ISOLATED: Channel Diversion			
Erosion and flushing of large quantities of material in "new" channel - especially if not lined	Flooding and increased suspended solids introduced into water column	High	Line channel or use a water diversion tube/ structure
Dam poorly sealed	Increased water pumping and disposal concerns, potential washout of dam and flooded work area	High	Ensure there are sufficient materials at hand to keep dams sealed
Dam failure	Work area flooding, increased suspended solids introduced into water column and safety	High	Have additional dam building materials at hand (*i.e.,* median barriers and water-filled dams)
TRENCHLESS: Bore			
Caving-in of bellhole	Failure of bore leads to subsequent attempts and possible additional land requirements	Low	Ensure sufficient land is obtained to attempt subsequent attempts and a protection plan is in place to minimize land disturbance
Bellholes fill with water	Inability to de-water bell-holes leading to abandonment of technique	Medium	Ensure measures are in place to handle de-watering and approvals in place for alternative techniques
Boulders prevent punching or ramming tool from progressing	Failure leads to subsequent attempts and possible additional land requirements	Medium	Ensure sufficient land is obtained to attempt subsequent attempts and ensure approvals are in place for alternative techniques
TRENCHLESS: Punch/Ram			
Boulders prevent punching or ramming tool from progressing	Failure leads to subsequent attempts and possible additional land requirements	Medium	Ensure sufficient land is obtained to attempt subsequent attempts and ensure approvals are in place for alternative techniques

Table 4.5 Risk Considerations for Watercourse Crossing Methods, Cont'd

Selected Potential Problems[1]	Environmental Risk(s)	Scale of Risk[2]	Mitigation and/or Contingency Plan(s)
Bellholes fill with water	Inability to dewater bell-holes leading to abandonment of technique	Medium	Ensure measures are in place to handle de-watering and ensure approvals are in place for alternative techniques
TRENCHLESS: Micro-tunneling			
Caving-in of bellhole	Failure of bore leads to subsequent attempts and possible additional land requirements	Low	Ensure sufficient land is obtained to attempt subsequent attempts and a protection plan is in place to minimize land disturbance
Bellholes fill with water	Inability to de-water bell-holes leading to abandonment of technique	Medium	Ensure measures are in place to handle de-watering and approvals in place for alternative techniques
Boulders prevent punching or ramming tool from progressing	Failure leads to subsequent attempts and possible additional land requirements	Medium	Ensure sufficient land is obtained to attempt subsequent attempts and ensure approvals are in place for alternative techniques
TRENCHLESS: Horizontal Directional Drill			
Collapsed hole, stuck drill stem, lost tools	Failure leads to subsequent attempts and possible additional land requirements	Low	Ensure sufficient land is obtained to attempt subsequent attempts and ensure approvals are in place for alternative techniques
Loss of circulation	Failure leads to excavation to find cause of lost circulation and possible additional land requirements	Low	Ensure sufficient land is obtained for excavation and ensure approvals are in place for alternative techniques Activate contingency plan if frac-out is occurring or suspected
Drill mud seepage directly into watercourse	Prolonged sediment load and deposition	High	Ensure a drilling mud contingency plan is in place
Drill mud seepage onto land and then into watercourse	Prolonged sediment load and deposition	Medium	Ensure a drilling mud contingency plan is in place
Washout of cavities and collapse of right-of-way	Sink holes on right-of-way	Low	Ensure sufficient equipment is on site to strip topsoil, grade sink hole and reclaim area
	Sink holes under watercourse	Medium	Ensure a drilling mud contingency plan is in place
AERIAL: Bridge Attachment			
Target for vandalism	Release of product	Low	Ensure company has an emergency response plan tailored to address the issue
AERIAL: Self Supporting Bridge			
Target for vandalism	Release of product	Low	Ensure company has an emergency response plan tailored to address the issue

Notes: 1 Sources: Harder (1995), TERA (1996), authors' experience
2 Scale of risk incorporates probability of occurrence and severity of effect.

4.4 Economic Selection Considerations

In selecting a watercourse crossing technique, proponents and regulatory agencies must evaluate the economic considerations at each particular site. Ideally, the cost of protective measures should be related to the social or environmental "value" of the resource potentially at risk. For this reason, the economic costs associated with various construction techniques must be balanced against the potential adverse environmental effects.

4.4.1 Direct Costs

The direct costs of various crossing techniques are difficult to predict for the following reasons:

- depth of cover, pipe diameter and substrate composition will strongly influence the costs;
- most small crossings are constructed by mainline crews and are built into the line cost for construction of the entire pipeline;
- more difficult crossings bid at a fixed price will have a contingency factor built into the price to allow for subsequent attempts or contingencies;
- all crossings and site conditions are different and the actual costs may vary significantly;
- many contractors are reluctant to give actual prices since the industry is competitive based on bid prices; and
- maintenance costs of fish habitat mitigation /compensation.

Nevertheless, **Table 4.6** outlines the relative cost that can be expected based on various techniques and watercourse sizes.

4.4.2 Indirect Costs

In evaluating the economics of a crossing, possible reductions in indirect costs are often overlooked. For instance, directionally drilling a watercourse may lead to considerable savings since no bank reclamation or ongoing maintenance will be necessary in that location and mitigation requirements for other resources (*e.g.*, wildlife habitat) may be reduced or avoided. Conversely, horizontal directional drilling may be disproportionately expensive if contractors are unavailable, extensive geotechnical evaluation is needed prior to construction or large volumes of drilling fluids require disposal. **Table 4.7** identifies relative costs associated with various activities and requirements of each watercourse crossing method.

Table 4.6 Relative Costs[1,2] of Watercourse Crossing Techniques

Technique	Small Watercourses <10 m Wide	Medium Watercourses 10-20 m Wide	Large Watercourses >20 m Wide
OPEN TRENCHED			
i) Plow	low	n/a[3]	n/a
ii) Bucket / Wheel Trencher	low	n/a	n/a
iii) Hoe	low	low	low to high
iv) Dragline	n/a	high	high
v) Dredging	n/a	high	high
ISOLATED			
i) Flume	low to moderate	moderate	n/a
ii) Dam and Pump	low to moderate	moderate	n/a
iii) High Volume Pump Bypass	low to moderate	moderate	n/a
iv) Coffer Dam	n/a	high	high
v) Channel Diversion	n/a	high	high
TRENCHLESS			
i) Boring	low to moderate	moderate	moderate
ii) Punching / Ramming	low to moderate	moderate	high
iii) Horizontal Directional Drilling	low to high	low to high	low to high
iv) Micro-tunnelling	n/a	very high	very high
AERIAL			
i) Bridge Attachment[4]	low to moderate	low to high	low to high
ii) Self-Supporting Bridge or Span	moderate to high	high	high

Notes:

There are many watercourse characteristics such as width, depth, channel shape, flow volume and substrate composition that affect the cost of each crossing. Most crossings have to be evaluated on a case by case basis. The above relative costs are based on the following assumptions:

- No bedrock is encountered during construction (*i.e.,* drilling and blasting costs are not considered).
- Single pipe, small diameter crossings (4" to 12").
- Larger, more complex crossings should be assessed on a site-specific basis.
- All isolation techniques assume trench excavation by backhoe.

1. This table identifies relative costs of construction methods compared to the lowest cost, technically feasible technique that would be selected if no consideration was made of environmental risk.

2. The provision of relative costs in the table does not imply that the crossing method is generally environmentally suitable - see Table 4.7.

3. n/a = not applicable / practical

4. The bridge used to attach the pipeline to in the ‘Bridge Attachment’ option must be along the pipeline route or additional costs will be incurred to reach the bridge.

Table 4.7 Economic Considerations of Watercourse Crossing Methods

Activities and Requirements of Watercourse Crossings	Type of Technique															
	Open Trenched					Isolated					Trenchless				Aerial	
	Plow	Trencher	Hoe	Dragline	Dredging	Flume	Dam and Pump	High Volume Pump	Coffer dam	Channel Diversion	Bore	Punch / Ram	Horizontal Directional Drill	Micro-tunnelling	Bridge Attachment	Self-Supporting Clear Span Bridge
Design and geotechnical investigation	L	L	M	M	M	M	M	M	H	H	M	M	H	M	H	H
Availability of experienced contractors and the ability to obtain competitive bids	M	L	M	H	H	M	M	M	H	H	M	H	H	H	H	H
Special permits and approvals	M	M	M	M	M	M	M	M	M	H	L	L	L	L	H	H
Extra temporary workspace	L	L	M	H	H	M	M	M	H	H	M	M	H	M	L	H
Land surveying	L	L	M	M	M	M	M	M	M	H	M	M	H	M	L	H
Clearing	L	L	M	H	H	M	M	M	M	H	M	M	M	M	L	L
Grading	M	M	M	M	M	L	M	M	L	H	L	L	L	M	L	L
Trenching / drilling	L	L	M	H	H	H	M	M	H	H	M	M	H	H	X	X
Special materials	M	M	M	M	M	H	H	M	H	H	M	M	H	M	H	H
Special equipment	M	M	M	H	H	H	H	H	H	H	H	H	H	H	H	H
Disruption of navigation and recreation	L	L	M	H	H	H	H	H	H	H	X	X	X	X	X	X
Dewatering	X	L	M	M	M	H	H	H	H	H	H	H	X	H	X	X
Special instream mitigative measures	L	L	M	M	M	H	H	M	H	H	X	X	X	X	X	X
Bank reclamation and restoration	M	M	M	H	M	M	M	M	H	H	X	X	X	X	X	X
Inspection	L	L	M	H	H	H	H	H	H	H	L	L	H	M	H	H
Site / work area access	L	L	M	H	H	M	M	M	H	H	M	M	H	M	H	H
Operations and maintenance	M	M	M	M	M	M	M	M	M	M	L	L	L	L	H	H
Habitat compensation	M	M	M	M	M	M	M	M	M	M	X	X	X	X	X	X

Notes:

H - High — Greater time and cost requirements than with traditional hoe construction
M - Moderate — Traditional construction costs and time requirements
L - Low — Less than traditional construction costs and time requirements
X - Nil — No costs or time requirements

4.5 Crossing Method Selection

4.5.1 Pipeline Crossings

The selection of a watercourse crossing method often causes the greatest conflict between industry and regulatory agencies. In recent years, the expectations of the regulatory agencies have evolved to the point that in some jurisdictions, proponents are informed that no instream activity is permitted in flowing waters that have the potential to support any fish. In other jurisdictions, industry has become accustomed to a regulatory environment that permits instream activity as long as it is not within restricted activity periods. In either situation, it is prudent to select a crossing method in a logical and reproducible manner based on sensitivity and mitigation potential.

In selecting a watercourse crossing method, many factors must be taken into consideration. These include, among others:

- pipeline diameter;
- crossing width, depth and flow characteristics;
- environmental sensitivity;
- geotechnical concerns;
- substrate composition;
- hydrological data;
- costs;
- navigation;
- amount of working space required and available;
- regulatory constraints;
- equipment availability;
- contractor expertise;
- downstream water users;
- landowner and community issues;
- engineering constraints; and
- season.

The selection of a final method is an exercise in striking a balance among the considerations listed above and potentially others, to derive the most practical solution. The method that is preferred is usually that which is technically feasible and offers the required level of environmental protection for the lowest cost.

Recent projects have related crossing methods to established sensitivity criteria for each watercourse. This leads to a reproducible selection of crossing methods. A more detailed matrix included in the application may allow some regulatory agencies to follow the logic behind the selection process and approve in principle other crossings as long as the proposed methods are used.

Since there are many factors, more complicated crossing selection flow diagrams have usually not been practical. It, therefore, falls upon the planner and engineer to use professional judgment and experience to evaluate all the factors in the final technique selection.

Table 4.8 summarizes considerations that can be used in selecting a watercourse crossing technique. The table is based on generic crossings and, where several techniques are suggested, the decision as to which will be selected will depend on detailed evaluation of specific concerns.

Table 4.8 provides guidance for the selection of a crossing technique. However, the most appropriate technique for a specific project should be determined on a case-by-case basis. Depending on circumstances, regulatory agencies may have different requirements in regard to their preferred method of crossing. For example, DFO may consider such factors as site location, geographic particularities, type of fish communities affected, regional fisheries management priorities, etc., which may lead to regional differences in preferred crossing methods. There is no automatic selection process.

It should be recognized that no one technique is a panacea for environmental protection and both regulatory and industry representatives must be familiar with the advantages and disadvantages as well as the risk(s) associated with each technique. These are discussed in Section 4.4.

In many situations, regulatory agencies are asked to approve crossing methods with insufficient data and, consequently, take a conservative approach. In these situations, the agencies have responded with an assumption that aquatic resources may be adversely affected unless the proponent indicates otherwise. The onus falls on the proponent to undertake a suitable assessment to assist in the selection of the crossing technique and to communicate the probability of success of the method selected to all parties included in the review of the project. Detailed information, extensive site-specific planning and communication of procedures between the proponent and contractors are required to ensure high probability of success. Where insufficient information is submitted, the proponent can expect that the project may not be reviewed in a timely manner or may be approved only with the most restrictive conditions.

Table 4.8 Pipeline Crossing Construction Technique Selection Considerations

Watercourse Construction Method		Small Watercourse <10 m Wide			Medium Watercourse 10-20 m Wide			Large Watercourse >20 m Wide		
		Environmental Sensitivity[1]			Environmental Sensitivity[1]			Environmental Sensitivity[1]		
		Low	Moderate	High	Low	Moderate	High	Low	Moderate	High
OPEN TRENCHED	Plow	Y	x	x	n/a	n/a	n/a	n/a	n/a	n/a
	Wheel Ditcher	Y	x	x	n/a	n/a	n/a	n/a	n/a	n/a
	Backhoe	Y	x	x	Y	Y	x	Y	Y	x
	Dragline	n/a	n/a	n/a	$	$	x	Y	Y	x
	Dredging	n/a	n/a	n/a	$	$	x	Y	Y	x
ISOLATED	Flume	Y	Y	Y	Y	Y	Y	$	Y	Y
	Dam and Pump	Y	Y	Y	Y	Y	Y	$	Y	Y
	High Volume Pump	Y	Y	Y	Y	Y	Y	$	Y	Y
	Coffer Dam	n/a	n/a	n/a	$	Y	Y	$	Y	Y
	Channel Diversion	n/a	n/a	n/a	$	Y	Y	$	Y	Y
TRENCHLESS	Boring	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Punching	Y	Y	Y	Y	Y	Y	$	$	$
	Micro-tunnelling	n/a	n/a	n/a	$	$	Y	$	$	Y
	Horizontal Directional Drill	$	Y	Y	$	Y	Y	$	Y	Y
AERIAL	Bridge Attachment	$	$	Y	$	$	Y	$	$	Y
	Self-Supporting	$	$	Y	$	$	Y	$	$	Y

NOTES:

1. Environmental sensitivity levels of watercourses are dependent on factors that vary regionally across Canada. The proponent, in consultation with provincial, territorial and federal fisheries authorities and other aquatic specialists, should determine the environmental sensitivity of a particular watercourse crossing location. Parameters such as species present, habitat use, season, downstream use by water users, flow, thermal regime and the findings of an aquatic assessment may be included in a determination of sensitivity (see Table 4.2 for detailed assessment parameters).

2. Watercourse sizes are defined below.

Small
- <10 m bankfull width with flows that can be readily dammed or pumped for isolated crossings

Medium
- 10-20 m bankfull width which can be generally dammed, flumed or pumped and can be excavated by backhoes from each bank

Large
- >20 m bankfull width that are too wide to construct from the banks unless specialized equipment is used. These cannot be dammed, flumed or pumped

3. Y - the method is generally environmentally suitable, but may require habitat compensation measures

   $ - the method is environmentally acceptable, however, may not be practical due to the high construction cost

   x - this method is generally not environmentally suitable, but may be permitted if habitat compensation is implemented

   n/a - not usually practical from an engineering or construction standpoint

   Adapted from Alberta Environment 1988a

4.5.2 Vehicle Crossings

In selecting a vehicle crossing technique, many factors must be taken into consideration. These include, among others:

- pipeline construction technique;
- crossing width, depth and flow characteristics;
- environmental sensitivity;
- geotechnical concerns;
- substrate composition;
- hydrological data;
- costs;
- navigation;
- amount of working space;
- regulatory constraints;
- equipment availability;
- contractor expertise;
- construction season;
- engineering constraints;
- season of use;
- proximity of alternative crossing structures;
- frequency of use;
- duration of use;
- weight of equipment; and
- contractor's responsibilities.

As with the selection of pipeline crossing method, the selection of a vehicle crossing technique also involves striking a balance between the considerations listed above and potentially others, to derive the most practical solution. The technique that is preferred is usually that which offers the required level of environmental protection for lowest cost based on the pipeline construction technique selected.

Table 4.9 summarizes considerations that can be used in selecting a vehicle crossing technique. The table is based on a generic crossing where several techniques are suggested. The decision as to which will be selected will depend on detailed evaluation of specific concerns and pipeline construction techniques.

Table 4.9 Vehicle Crossing Technique Selection Considerations

Vehicle Crossing Method		Small Watercourse <6 m Wide – Environmental Sensitivity: Low	Moderate	High	Medium Watercourse 6-15 m Wide – Environmental Sensitivity: Low	Moderate	High	Large Watercourse >15 m Wide – Environmental Sensitivity: Low	Moderate	High
BRIDGES	Existing Bridge	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Temporary Bridge	Y	Y	Y	Y	Y	Y	$	$	$
	Ice Bridge	Y	Y	Y	Y	Y	Y	Y	Y	Y
FILLS	Swamp Mats	Y	x	x	Y	x	x	n/a	n/a	n/a
	Log/Pipe Fill	Y	x	x	x	x	x	n/a	n/a	n/a
	Snow Fill	Y	Y	x	Y	Y	x	n/a	n/a	n/a
	Ramp and Culvert/Flume	Y	Y	x	Y	x	x	n/a	n/a	n/a
FORDS	Travel Pad	$	x	x	Y	x	x	Y	x	x
	Ford	Y	x	x	Y	x	x	Y	n/a	n/a
BARGE	Barge	n/a	n/a	n/a	$	$	$	$	Y	Y

NOTES:

1. Environmental sensitivity levels of watercourses are dependent on factors that vary regionally across Canada. The proponent, in consultation with provincial, territorial and federal fisheries authorities and other aquatic specialists, should determine the environmental sensitivity of a particular watercourse crossing location. Parameters such as species present, habitat use, season, downstream use by water users, flow, thermal regime and the findings of an aquatic assessment may be included in a determination of sensitivity (see Table 4.2 for detailed assessment parameters).

2. Watercourse sizes are defined below.

Small	Medium	Large
• watercourses <6 m bankfull width	• watercourses 6-15 m bankfull width	• watercourses >15 m bankfull width

3. Y - the method is generally environmentally suitable, but may require habitat compensation measures.

   $ - the method is environmentally acceptable, however, may not be practical due to the high construction cost relative to the sensitivity.

   x - this method is generally not environmentally suitable, but may be permitted with habitat compensation.

   n/a - not usually practical from an engineering or construction standpoint.

   Adapted from Alberta Environment 1988a

5 Environmental Mitigation Procedures

The following subsections outline various environmental mitigation procedures that should be considered and, if necessary, implemented to ensure a successful crossing.

5.1 Planning and Design

The level of planning and design undertaken for a watercourse crossing will depend upon watercourse sensitivity and project magnitude as well as the jurisdictional requirements. Prior to application, the applicant should ensure that the information requirements are clarified with the regulatory agencies and that required information is submitted as part of the documentation. Failure to do so may result in unnecessary delays in review.

Consultation with the appropriate regulatory agencies is advisable in all jurisdictions since it generally simplifies the planning process and facilitates approval of the application. Environmental non-government organizations with an interest in fish, fish habitat or aquatic environments (*e.g.*, Trout Unlimited Canada), other environmental groups, landowners, users (*e.g.*, outfitters and guides), Licensed water users and other interested parties (*e.g.*, Aboriginal groups) should also be consulted when construction is planned in sensitive environments. As with the regulators, failure to undertake appropriate stakeholder consultation may result in unnecessary delays and added costs.

The following detailed plans could be required as part of a complete application, or should be considered for a construction bid package:

Typical Crossing Design[1]	Contingency Plans[2]
Detailed Crossing Design [1]	- Alternative crossing methods
Environmental Protection Plan[2]	- Floods
Environmental Alignment Sheets	- Waste and hazardous material
Crossing Detail Alignment Sheets	- Spills
Reclamation Plan[2]	- Drilling mud release
Erosion and Sediment Control Plan[2]	- Archaeological or palaeontological discovery
Habitat Restoration and Enhancement Measures[2]	- Rare and endangered species discovery
Compensation Agreements	- Fire
Post-Construction Monitoring	- Construction delays

Notes:

1. These generally are engineering documents but may be developed to include environmental protection measures.

2. Components of these plans are included in Section 5.2 of this document. For contract and application purposes it is easier to have these as stand alone documents.

DFO, and other applicable regulators, consider the contents of some of these plans (*e.g.*, Erosion and Sediment Control Plan) to be very important when reviewing and understanding pipeline construction related activities to be undertaken at medium and highly sensitive crossings.

In jurisdictions not requiring such detailed information, proponents should consider inclusion of as much information as possible in the construction bid documents to ensure that the contractors are bidding appropriately and that there will be no "extras". With their inclusion in the bid documents, there is a greater level of confidence that the contractors and inspectors will act in the manner expected by the proponent and regulatory agencies and not "do it the way it is always done".

5.2 Crossing Construction

The following construction procedures are discussed regarding the installation of vehicle crossings and watercourse crossings:

- general;
- surveying;
- clearing;
- topsoil handling;
- grading;
- welding and weighting;
- instream blasting;
- construction of isolated crossings;
- pipe installation;
- instream sediment control;
- subsurface drainage control;
- backfilling;
- surface erosion control;
- clean-up and reclamation; and
- temporary vehicle crossings.

Standard environmental protection measures and procedures (*e.g.*, Alberta Environment 1988a or other region-specific guidance) should be employed during construction although the following specific considerations are examples of additional measures that could be incorporated during each stage of construction where appropriate.

5.2.1 General Mitigation Procedures

The following measures are general in nature and should be considered regardless of construction activities. Such measures should be considered for implementation into the environmental protection plan whenever practical.

- Schedule construction to occur during periods of lowest sensitivity.

- All reasonable efforts should be made to minimize the duration of instream work.
- Abide by all relevant timing constraints (fish, ungulate, avian, etc.). Ensure that no construction activity occurs within the wetted portion of the channel during the restricted activity period.
- Prepare contingency plans for fuel and hazardous waste spills, streambank erosion, storm runoff and floods.
- Prepare an emergency monitoring and response plan for use in the event of a frac-out during a horizontal directional drill. If drilling fluids are entering a waterbody, follow the contingency plan. The appropriate environmental regulatory agencies must be notified immediately.
- Do not discharge or dispose of petroleum products and/or waste into waterways or onto the ground.
- Ensure waste storage areas are sited to prevent blockage of drainage or risk introduction of waste material into a watercourse.
- Change oil, refuel and lubricate mobile construction equipment well away from the normal high water mark of a waterbody to minimize the potential for water pollution.
- Ensure that all oil changes, refuelling and lubrication of immobile equipment well away from the normal high water mark of a waterbody is undertaken in a manner such that any spillage will not enter the waterbody.
- Spent oils, lubricants and filters, etc., are to be collected and disposed of at an approved location and in an appropriate manner.
- Ensure that the following measures are employed to minimize the risk of fuel spills:
  - all containers, hoses and nozzles are free of leaks;
  - all fuel nozzles are equipped with automatic shut-offs;
  - operators are trained and stationed at both ends of the hose during fuelling unless the ends are visible and are readily accessible by one operator; and
  - fuel remaining in the hose is returned to the storage facility.
- Ensure that all fuel and service vehicles carry a spill kit with a minimum of 25 kg of suitable commercial sorbent material, 30 m^2 of 6 mil polyethylene, a shovel and one fuel barrel (lid removed).
- Store fuel within containment berms constructed to a capacity of 110% of the fuel stored or within double-walled tanks.
- Do not store hazardous materials, chemicals, fuels, or lubricating oils, near the normal high water mark of a waterbody or near any surface drainage location. All such storage areas must be suitably contained.
- Fuel trucks, fuel storage areas, pumps, generators and other sources of deleterious substances must be within a containment system of sufficient capacity to ensure that deleterious substances do not enter fish habitat.
- Do not perform concrete coating activities near a watercourse unless suitable isolation from surface drainage and watercourses is ensured.

- Do not wash any type of equipment or machinery in watercourses or lakes. Control wastewater from construction activities, such as equipment washing or concrete mixing, to avoid discharge directly into any body of water.
- Ensure that the hydraulic, fuel and lubrication systems of any equipment working instream are in good repair to avoid leakage. Operate all equipment in a manner that prevents deleterious substances from entering fish habitat.
- Consider using vegetable based hydraulic oils in hydraulic systems working near watercourses or instream.
- Thoroughly inspect and clean equipment of oils, mud and vegetative debris before commencement of project.
- Any aquatic plants uprooted or cut during excavation should be removed and disposed of on land in an approved disposal site. It is important that these plants not be deposited in another body of water.
- Determine the presence of aquatic or riparian noxious weeds which construction equipment could carry forward from an infested to a clean area.
- Hose down, thoroughly wash potentially infested equipment and purge and clean all pumps before proceeding from one area to the next if noxious weeds or other pest species such as zebra mussels are known to be present in the area.
- Locate sources of clean gravel, cobble and riprap, if needed, prior to construction and place onsite for stabilization and restoration.
- Ensure that all material that is placed within the wetted perimeter of a watercourse is not toxic to fish.
- Ensure the appropriate vehicle crossing technique is employed (see Section 4.6.2).
- Wash all equipment transferred between major watersheds to ensure that aquatic pests are not transferred.
- Where water is pumped from fish habitat for any purpose, intakes are to be screened according to DFO's *Freshwater Intake End-of-Pipe Fish Screen Guideline* (DFO 1995c).

5.2.2 Surveying

Since the surveyor may select the initial crossing location, it is important that the following points be considered.

- Verify the final alignment of watercourse crossings to ensure that areas of particular concern are avoided. Environmental staff/consultant and/or project manager should conduct verification.
- Survey parallel to the fall line on approach slopes of watercourses. Avoid side slopes, drainages and unstable terrain. Survey pipeline crossings perpendicular to watercourses, wherever practical.
- Ensure sufficient extra workspace is taken for working area on the approach slopes and at the watercourse crossing. Workspace boundaries should be well marked.
- Locate staging area at least 10 m away from streambanks, where topographic conditions permit.

- Minimize staging area size needed to construct the watercourse crossing.
- Identify and locate existing lines, especially hot lines, including burial depths.
- Mark or flag any sensitive environmental features within construction area.
- Ensure a photographic record is made of all significant features to be protected or restored.

5.2.3 Clearing

Clearing can lead to erosion of the approach slopes, bed and banks as well as sedimentation and the obstruction of the watercourse. The following points are designed to minimize the potential adverse environmental effects of clearing (*e.g.*, increased potential for erosion and sedimentation of the watercourse) and should be considered for inclusion in the environmental protection plan.

- Flag clearing boundaries prior to clearing operations.
- Minimize clearing to prevent erosion and loss of riparian habitat.
- Consider using tracked vehicles on steep terrain to minimize the need for shoo-flies.
- Limit nontracked vehicle traffic to approved shoo-flies on steep approach slopes.
- Postpone clearing of slopes and banks until immediately prior to construction, unless otherwise approved by the regulatory authority/Environmental Inspector and landowner. Avoid preclearing in the vicinity of watercourses.
- Leave a temporary uncleared buffer zone extending back from the crest of erosion prone slopes.
- Postpone disturbance of the vegetated buffer zone of watercourse until necessary.
- Remove trees, debris or soil inadvertently deposited within the high water mark of watercourses in a manner that minimizes disturbance of the bed and banks. Do not fell, stand or yard trees across a watercourse. Do not drive logs into a watercourse even when dry.
- Implement Surface Erosion Control Measures as outlined in Section 5.2.11.
- Avoid long-distance skidding of timber on steep slopes adjacent to watercourses.
- Retain timber for riprap, logfill crossings, temporary bridges, rollback and/or corduroy, if warranted. Only use timber approved of by the applicable government representative or landowner. Place material so as not to hinder crossing construction.
- Chip or mulch slash and spread on steep erosion-prone slopes.
- Leave an undisturbed organic mat on the work side of the right-of-way as a buffer zone to limit the potential for sediment to enter the watercourse.
- Delay grubbing on slopes adjacent to a watercourse or within 10 m of the watercourse banks until construction of crossing is imminent.
- Restrict root grubbing near watercourses. Do not grub within 10 m of a watercourse except along the trench line. Only grub the spoil pile area if absolutely necessary. Leave an undisturbed organic mat on work side to minimize the potential for introduction of sediment into the watercourse.

- Maintain low vegetation within the 10 m buffer of watercourses to the extent practical by walking, storing and constructing over the undisturbed areas.
- Note that clearing and grubbing within 10 m of watercourses may be appropriate if completion of these activities will result in a reduction in erosion and sedimentation risk.
- Dispose of all nonmerchantable timber and slash not used for corduroy or rollback to the satisfaction of the landowner and regulatory authority. Methods of disposal include burning, chipping and mulching, or bucking and stockpiling (firewood). Combinations of methods may be needed depending on site and regulatory conditions.
- Do not locate burn areas within the wetted perimeter of a watercourse and avoid locating burn piles on organic soils. Dispose of all partially burnt stumps and logs above the high water mark to the satisfaction of the landowner and regulatory authority.
- Do not use tires, petroleum products, waste oil, waste chemicals or other wastes to ignite fires.
- Suspend clearing during heavy rains.

5.2.4 Topsoil Handling

Poor topsoil handling can result in increased erosion, sedimentation and possibly blockage of streamflow and insufficient reclamation following construction. The following points should be considered.

- Implement Surface Erosion Control Measures as outlined in Section 5.2.11.
- Strip topsoil under nonfrozen and/or dry conditions, where practical.
- Delay stripping of approach slopes, floodplains and banks until immediately prior to construction.
- Strip topsoil from all areas to be graded.
- Strip topsoil during nonfrozen conditions from all areas to be used for approach slope spoil storage and from where instream spoil sump is to be constructed.
- Ensure graded and excavated subsoil are stored separately from topsoil.
- Stockpile salvaged topsoil in a location that will prevent erosion and siltation of the watercourse.
- Place topsoil in distinct piles above the high water mark in a manner that does not block drainage or runoff, construction activities, or replacement of grade material or trench spoil and prevents erosion and siltation into the watercourse.
- Contour and stabilize with an approved cover crop if topsoil piles are to remain through the winter or for an extended period of time.
- Suspend topsoil handling during wet conditions. Recommence once field conditions improve.

5.2.5 Grading

Poor grading can result in increased erosion, slope instability, sedimentation and blockage of streamflow. The following points should be considered where appropriate.

- Ensure snow graded from the right-of-way is stored in a manner that does not lead to increased erosion during spring melt.
- Ensure that melting "dirty" snow is not allowed to run-off directly into watercourses.
- Implement Surface Erosion Control Measures as outlined in Section 5.2.11 unless approved by a geotechnical engineer.
- Minimize grading on steep slopes. Grading should be limited to only permit access for tracked vehicles. Rubber-tired traffic should be limited to approved shoo-flies.
- Do not place graded material on steep slopes or closer than 20 m to the crests of slopes. Cuts and fills should not exceed 3:1 slope.
- Minimize disturbance of natural drainage channels during grading; avoid blocking channels with graded material.
- Remove bank grade with backhoe and store it a sufficient distance back from the watercourse.
- Grade away from watercourses to reduce the risk of material entering a watercourse. Do not place fill material in a watercourse during grading.
- Grade only the trench line and spoil containment areas. Grade the work side and crossing approaches only if warranted for safe operation of equipment. Grading within 10 m of the watercourse may be appropriate if completion of this activity results in a reduced erosion and sedimentation risk.
- Minimize the area of disturbance along the streambank. Do not grade the entire width of the right-of-way in proximity to a watercourse.
- Minimize grading when constructing bridge, fill or ford crossings.
- Plow and store snow for snowfill crossing prior to earth-moving activity to maintain clean snowfill.
- Contour and stabilize excess grade material if piles are to remain through the winter or for an extended period of time.

5.2.6 Welding and Weighting

Welding and weighting of pipe should be undertaken in a manner that allows quick installation and the least amount of adverse environmental impact. The following points should be considered where appropriate.

- Assemble pipeline in upland area and utilize "push-pull" or "float" technique to place pipe in trench whenever water and other site conditions allow.
- Complete welding, coating, testing and weighting of the pipe prior to commencement of trenching. Completion of welding, coating and weighting of the pipe may be deferred, to a limited extent, at large watercourses where a substantial instream trenching period is anticipated.

- Ensure that sufficient equipment is available to move long heavy sections of pipe efficiently at long crossings.

5.2.7 Instream Blasting

When considering instream blasting as an approach to remove bedrock for the installation of a pipeline watercourse crossing, these measures should be followed:

- Consider less destructive or more controlled methods of removing bedrock, if practical, such as ripping. These methods are preferable to blasting.
- Consult with provincial or territorial fisheries biologists, wildlife biologists and regional DFO representatives in addition to other regulatory agencies early in the planning phase should blasting in or near streams be considered.
- Consult with DFO as early as possible in the planning process if the use of explosives is unavoidable, to identify and discuss practical alternatives, aquatic resources and mitigation measures. DFO may, upon review of a project proposal, provide a letter of advice, issue an Authorization under Section 32 and/or Subsection 35(2) of the *Fisheries Act*, or decide not to issue Authorization(s). In arriving at one of these determinations, DFO will take into account, among other things, whether:
  - the use of explosives is the only technically feasible means of breaking bedrock such that it can be excavated from the trench;
  - sensitivity of habitat, fish presence and timing; and
  - the use of explosives is required to alleviate an emergency situation.

Mitigation measures specific to the use of explosives in or near fisheries water may be implemented in order to effectively minimize the destruction of fish and/or the HADD of fish habitat. These measures could include, but are not limited to the following:

- use of staggered/delayed blasting times in conjunction with decked charges to reduce overall shock wave;
- scheduling of blasting for periods of least biological activity for the watercourse, especially avoiding spawning, incubation, overwintering and migration periods;
- deploying bubble/air curtains to dampen the shock wave;
- displacing fish from blast area (e.g., use small charge blasting caps) and employ shock wave buffers (e.g., air curtains) to minimize adverse effects;
- using confined explosives (i.e., contained within a substrate) instead of unconfined explosives;
- avoiding the use of ammonium nitrate based explosives, specifically nitrate-fuel oil mixtures in or near water due to the potential for toxic by-product production (ammonia).

5.2.8 Construction of Isolated Crossings

The following mitigative measures should be implemented during construction of crossings using an isolation method:

- Maintain 100% of downstream flow at all times.
- Water from flumes, pump-around, diversions or other methods used to maintain downstream flow must not cause erosion or introduce sediment into the channel.
- If a pump-around method is used to maintain downstream flow, back-up pumps with adequate capacity to maintain 150% of downstream flow must be on site at all times and ready to take over pumping should the operating pumps fail. The operating pumps should be continually monitored to ensure downstream flow is maintained at all times until the dam materials are removed and normal flows restored to the channel.
- Pump intakes must not disturb the streambed. Pump intakes used in fish bearing waters must be screened with a maximum mesh size of 2.54 mm and a maximum screen approach velocity of 0.038 m/s.
- Earthen berms should not be used for isolation.
- All berms and material must be completely removed from the channel and the streambed and bank profiles be returned to preconstruction conditions at the end of the project.
- Sediment laden water in the work area should be discharged to an upland vegetated area prior to removal of the isolation dams.
- Fish salvage should be conducted using a seine net, dip net and/or electrofishing and the fish released unharmed upstream. Fish salvage should be undertaken within any isolated areas prior to and during dewatering activities. In addition, fish salvage should be undertaken on any bypass structures such as diversion channels and flumes prior to them being dewatered after use. Fish salvage may require a permit from the province.

5.2.9 Pipe Installation

The specific procedures that may be implemented during pipe installation depend on the crossing technique. See Dwgs. 1 to 11 for specific techniques. Other general measures include:

- Stop trenching activities short of watercourse banks or where deep burial is to occur to prevent silty trench water from entering the watercourse. Leave hard trench plugs in place until the watercourse crossing has been initiated. The recommended minimum plug width is 3 m.
- Construct a sump, with berms, silt fences or straw bale filters to contain excavated instream spoil so that silty runoff does not re-enter watercourse. Prevent instream spoil from flowing off right-of-way (see Dwgs. 16, 17 and 18).
- Ensure subsurface flow along the stream channel is maintained if critical habitats downstream could be affected by a blockage in flow.

- Dewater the trench onto stable surfaces in a manner that does not cause erosion of soils, sedimentation of watercourses, or where icing will not be a problem.
- Dewater the trench or boreholes so that the water is released into a well vegetated area or settling basin and does not directly re-enter any watercourse. Water returning to a watercourse must be equal to or in exceedance of background quality of the watercourse.
- Salvage vegetation plugs from streambank to aid in bank reclamation. Store in a manner that they can be replaced during clean-up.
- Suspend instream work if sedimentation is occurring. Implement further protection measures to control sediment loading.
- Ensure the watercourse is restored to its natural gradient and elevation to prevent barriers to fish movement.
- Install spare lines, where appropriate, for future use.

5.2.10 Subsurface Drainage Control

Drainage along the unconsolidated backfilled trench may cause instability and erosion, resulting in watercourse blockage and/or sedimentation, as well as threaten pipe integrity. Subsurface drainage must be diverted from the backfilled trench. The following points should be considered to ensure appropriate drainage.

- Install trench breakers constructed of sandbags, bentonite, urethane foam or other compacted impervious materials to force bellhole seepage along the pipeline trench to the surface on steep slopes (see Dwg. 19). Determine the location of trench breakers by onsite investigation considering the potential for subsurface flow, erodibility of backfill material and degree of slope. Mark location of trench breaker prior to backfilling.
- Install trench breakers adjacent to watercourses, at edges of wetlands and on other similar sites where unconsolidated backfill or organic materials are prone to washing out.
- Install subdrains or pole drains to divert shallow groundwater flow from the right-of-way and to improve slope stability (see Dwgs. 20 and 21).
- Install trench breakers on each side of a wetland where the pipeline trench crosses and may drain the wetland.

5.2.11 Surface Erosion and Sediment Control

Surface erosion should be controlled prior to, during and following crossing construction to minimize sedimentation. Erosion control measures should be considered as a primary means of sediment control and incorporated into all watercourse crossings during the planning stage. The following measures should be considered to minimize the amount of erosion and sedimentation.

- Regulate drainage from construction areas to prevent erosion and sedimentation.
- Ensure no ditch drains directly into a watercourse without proper sediment control devices.

- Install temporary berms on approach slopes immediately following clearing and grading.
- Install temporary silt fences (geotextiles or hay/straw bales) near the base of slopes if heavy rains or surface erosion could result in siltation of the watercourse (see Dwgs. 17 and 18).
- Install temporary silt fences (geotextiles or hay/straw bales) in any location where run-off from the right-of-way may flow into a watercourse.
- Inspect and clean silt fences on a regular basis, especially after heavy rainfalls.
- Install diversion berms and cross ditches, on disturbed steep approach slopes to divert surface water off the right-of-way (see Dwg. 22). Install sandbag, timber or bale berms on undisturbed pasture or well-sodded right-of-way. Determine location, type and direction of diversion berms in the field based on local topography, drainage patterns and land use. Ensure berms terminate in natural vegetation off the right-of-way. Stagger ends of berms as warranted. Install berms immediately downslope of trench breakers where installed. Ensure trench crown does not impede drainage or that a sunken trench does not act as a drainage ditch. All designs should be made with input from a geotechnical engineer.
- Rollback stored, salvaged or imported small diameter slash (<5 cm) and walk down with dozer on steep erosion prone slopes on non-agricultural land. Install netting, mat binders, tackifiers, pegged sod or other products as warranted.
- Revegetate with an approved seed mix, as soon as practical, at twice the annual standard pasture rate. Incorporate a cover crop seed (*i.e.,* biannual fall rye, annual oats or barley) into mix as a cover crop. Note: Biannual fall rye should be incorporated for summer or fall seeding and annual oats for winter or spring seeding.
- Transplant native shrubs, plant willow stakes, or utilize other bioengineering techniques such as brush layering or wattling as warranted on steep erosion prone slopes on non-agricultural land. Schiechtl (1980) discusses numerous bioengineering techniques (see Dwgs. 26, 27, 28).
- Consider applying netting or tackifier; laying and pegging sod, especially in urban areas; hydroseeding; seed impregnated mats; organic mulches such as straw, wood fibre, peat moss, wood chips or bark; brush matting; or other surface erosion control measures outlined in **Table 5.1**.
- Inspect erosion control structures until well established and stable, after major rainfalls and at least daily during periods of prolonged rainfall.
- Immediately repair erosion control structures that are found to be damaged.

5.2.12 Instream Sediment Control

The generation of sediments cannot always be avoided during the construction of watercourse crossings; however, there are methods that may be used to minimize and control the location, dispersion and extent of sediments transported downstream. These are discussed in detail in *Instream Sediment Control*

Techniques - Field Implementation Manual (Trow Consulting Engineers Ltd. 1996).

The use of filtering devices is not generally recommended since the materials have very low permeability rates, quickly loose their filtering potential and are susceptible to damage from streamflows. The use of geosynthetic textile products to filter silt and clays may only be appropriate in very low velocities ($<0.026\ m^3/s$).

Other instream sediment controls are designed to reduce water velocities and allow for settling of suspended materials in closer proximity to a trench excavation than would naturally occur. These controls are generally limited to controlling the transport of heavier suspended sediments that are temporarily within the water column. Such techniques are normally used in close proximity to the crossing since most of the coarser particles settle out naturally within a few hundred metres of the excavation.

Recent construction experience with sediment mats (*e.g.*, Sedimat) has indicated that placement of these woven mats downstream of the crossing, especially in sensitive habitats, traps large amounts of bedload and suspended sediment. These mats are removed after construction and, if biodegradable, can be used during bank restoration.

Special care is required when designing and installing instream sediment controls, particularly in flowing watercourses. Selection of the appropriate method for a stream, river, wetland or lake crossing is generally based on the following criteria:

- flow velocity and volume;
- crossing depth and width;
- seasonal conditions;
- environmental sensitivity;
- bed material; and
- trench excavation method.

Although conditions may appear suitable for instream sediment controls, their use must be carefully examined as their suitability and effectiveness are often overestimated. The use of instream sediment controls may be prohibited by factors such as: costs; physical obstructions (such as access, instream debris, freezing conditions, blockage of fish passage); potential downstream sedimentation as a result of installation, maintenance and removal; damming of flows; chance of failure; ability to handle floods and increased flows; and their potential to become sources of bed or bank erosion. The type, design and placement of instream sediment controls should only be undertaken by a hydrological engineer or other qualified person.

All instream controls should be installed prior to construction and maintained throughout their installation period. Where possible and practical, accumulated sediment should be regularly removed to prevent accidental transport of collected sediments should the device fail. Disposal should be in a location and manner such that accumulated sediment is not allowed to re-enter any drainage system or receiving waterbody. Where removal would only cause additional sedimentation, the deposited material should be left in place and permitted to be removed naturally during the freshet. Instream controls should be removed before spring freshet if they are used through the winter season and prior to freeze-up if used during the fall.

The following types of instream sediment controls have been used in the past although no information has been collected on the acceptability of these techniques by regulators nor their effectiveness:

- check dam approach using shallow geotextile dams or stone for small streams of low velocity;
- deflector approach by installing logs, rocks or geotextiles to divert sediment-laden flow from sensitive fish habitat and to promote deposition of suspended solids in artificially created back eddy; and
- covering spawning beds with geotextiles, or other suitable material, until construction is complete.

5.2.13 Backfilling

Backfilling should be performed in a manner that ensures erosion does not occur along the trench and that it does not result in a loss of fish habitat.

- Ensure backfill is well compacted on approach slopes and streambanks.
- Backfill with clean coarse material (*e.g.*, 2 cm diameter gravel or larger rock). All fill material is to be obtained from off-site and not from below the average high water level of any watercourse.
- Backfill from the centre of the watercourse towards the bank forcing silt-laden water back towards the ditch plugs. Silt-laden trench water should then be pumped onto vegetated land or into a sump.
- Lower backhoe bucket into water before releasing the backfill.
- Consider not backfilling instream trench, where sediment transport and sloughing will fill in trench and backfilling with existing or select backfill will create excessive downstream sedimentation.

5.2.14 Clean-up and Reclamation

Clean-up and reclamation should be performed to stabilize the disturbed area and to restore its aesthetic appearance.

- Commence clean-up at watercourses immediately following backfill and erosion control operations. Attempt to complete all phases of clean-up as quickly as practical. Where winter clean-up is hampered by frozen spoil and topsoil piles, complete rough clean-up prior to break-up and final clean-up after break-up.
- Remove corduroy from all locations wherever practical. Remove clay or sand caps overlying corduroy and ensure adequately sized culverts or other

methods of cross drainage are present in any capped corduroy that is left in place. Dispose of corduroy, slash and any remaining leaning trees in the same manner as used for disposal of slash from initial clearing.

- Regrade streambanks and approaches to preconstruction profile, or to a maximum of 3:1 unless directed by a geotechnical engineer.
- Replace topsoil and any salvaged trees or shrubs.
- Revegetate streambanks and approach slopes with an appropriate native seed mix or erosion control mix. Seed a cover crop of fall rye, barley, oats or sterile hybrids such as triticale or wheat/wheatgrass.
- Broadcast seed, harrow in or hand rake on slopes. A seed drill should be used on level areas such as floodplains wherever practical. Hydroseeding can be used where access is good.
- Develop specific procedures, in coordination with the appropriate federal, provincial or territorial agency, to prevent the invasion or spread of undesirable non-native vegetation (*e.g.*, purple loosestrife, Eurasian milfoil).
- Do not fertilize in the immediate vicinity of a watercourse unless requested by the landowner and approved by DFO.

5.2.15 Temporary Vehicle Crossings

Temporary vehicle crossings for equipment and materials are commonly associated with pipeline crossings. The following mitigative measures should be implemented to avoid environmental damage.

- Whenever possible, existing watercourse crossings should be used. Secondarily, clear span bridges or ice/snow bridges should be used for temporary crossings.
- Remove crossing structures, where feasible, prior to freeze-up (for summer construction) and prior to break-up (for winter construction). Remove structures by physical means, not blasting. Crossing structures may be left in place only for final touch-up (*e.g.*, reseeding) if no other access is available and if they are designed to withstand high water flows during spring break-up.
- Any temporary crossing and associated debris must be removed immediately after completion of the pipeline crossing and the disturbed area restored to preconstruction conditions.
- Only clean ice/snow should be used for construction of ice bridges.
- Sand or gravel should not be used for the ice bridge approaches. Approaches should be constructed of compacted snow and ice of sufficient thickness to protect the stream and banks.
- Ice/snow bridges must be notched open prior to spring break-up when safe to do so and any associated debris removed from the watercourse. Banks and approaches should be stabilized and restored to preconstruction conditions.
- Ensure that no excavation of the streambed occurs unless approved by DFO.
- If water extraction is necessary for the construction of temporary vehicle crossings, local regulations should be consulted for the maximum permissible withdrawal volume.

5.2.16 Abandonment

There are many factors to consider in deciding whether a section of pipeline crossing a water body should be abandoned in place or removed. More specifically, the risks associated with abandoning the pipeline in place, including the potential for contamination and pipe exposure, have to be weighed against the cost and environmental impact of removal (PASC 1996).

These trade-offs should be assessed on a site-specific basis, taking into account the size and dynamics of the water body, the design of the pipeline crossing, soil characteristics, slope stability, and environmental sensitivities. While these issues must be evaluated, in most cases it can be expected that abandonment-in-place will be the preferred option (PASC 1996).

Table 5.1 Erosion Control Techniques

Technique	Description	Advantages	Disadvantages	Comments
I. CONSTRUCTION PHASE				
Preserve existing vegetation	• maintain vegetation where practical • minimize grubbing and maintain root mat	• inexpensive • permits infiltration by water • native vegetation maintained • minimal surface disturbance	• possible congestion of construction traffic • may create unsafe working conditions • may impair erosion control in some conditions	• applicable for slopes, streambanks and floodplains • aids reclamation practices • good in areas with erodible soils, sensitive vegetation • standard procedure to minimize disturbance
Minimize grading	• reduce cut and fills for minor depressions / gradient changes	• inexpensive • reduces surface disturbance	• may create unsafe working conditions • may impair erosion control in some conditions	• applicable for gentle slopes, small hummocks and rolling topography • standard procedure to minimize disturbance
Silt fences (Dwg. No. 17)	• geotextile fences, partially buried, placed along slopes perpen-dicular to the fall line used to slow / block sediment transport along a slope • often at the base of slopes adjacent to watercourses • secured with steel rods or wooden posts	• prevents saturated spoil / slopewash from entering a watercourse • minimizes erosion	• possible obstacle to construction traffic • may washout / fail if not properly installed	• temporary measure used on slopes with erodible soils to minimize sediment release into watercourses prior to revegetation
Straw bales (Dwg. No. 18)	• bales used to slow / block sediment transport along a slope • secured with steel rods or wooden posts	• prevents saturated spoil / slopewash from entering a watercourse • minimizes erosion	• possible obstacle to construction traffic • may washout / fail if not properly installed	• temporary measure used on slopes with erodible soils to minimize sediment release into watercourses prior to revegetation

Table 5.1 Erosion Control Techniques, Cont'd

Technique	Description	Advantages	Disadvantages	Comments
Sediment trap	• excavate minor depression(s) to allow sediment to settle	• does not require specialized equipment • prevents large volumes of sediment from being washed away • may be used in conjunction with silt fencing / straw bales	• may obstruct construction traffic • spoil from sediment trap requires additional slope area • may create a bigger mess	• used for isolated areas prior to final clean-up • not common
Sandbag ditch plug (Dwg. No. 19)	• sandbags (not foam or bentonite) are placed in the trench as a ditch plug to prevent washout of organic streambank	• relatively inexpensive • may provide stable base for revegetation techniques	• labour intensive • may fail if incorrectly installed resulting in large sediment volume release	• used for watercourses with organic banks which are susceptible to washing out • must be keyed into trench walls for stability
Subdrains (Dwg. No. 20)	• buried conduits providing surface release of subsurface water • generally gravel wrapped in geotextile fabric or heavy plastic drain pipe(s)	• provides slope stabilization where springs are present • maintains pipeline integrity by preventing trench washout	• expensive / labour intensive • requires correct placement to be effective	• used in conjunction with cross ditches and diversion berms • geotechnical consultation is recommended for correct placement • correct installation is key
Temporary diversion berms	• low subsoil berm across entire right-of-way used to divert surface water flow off the right-of-way	• inexpensive • effective at diverting surface water flow • can be readily installed and repaired	• due to low profile of berm(s), over topping / washout can occur during major precipitation event • must be repaired on a daily basis	• applicable for approach slopes • permanent berms will replace temporary berms during rough clean-up • common practice
II. POST CONSTRUCTION / ROUGH CLEAN-UP PHASE				
Cross ditch & diversion berms (Dwg. No. 22)	• ditches and berms crossing entire right-of-way slowing runoff to minimize erosion	• very effective if constructed correctly • utilizes native materials • aids in reclamation and revegetation	• may impede operations and maintenance activities • not applicable for all soil types	• standard procedure for erosion control • must be correctly placed in relation to slope and natural drainage in addition to trench breaker locations

Table 5.1 Erosion Control Techniques, Cont'd

Technique	Description	Advantages	Disadvantages	Comments
Brush bundles, fascines or wattles	• bundles of live cuttings tied produce sausage shaped bundles • planted in shallow trenches anchored with wooden or live stakes	• can be used to direct or slow water movement and encourage vegetation growth on bank • don't require heavy equipment for installation	• provides very limited structural stability until rooted • least suitable during active growing season • may rot and require extensive maintenance • construction is labour intensive	• can be combined with other erosion control measures
Brush matting	• mattress-like layer of branches placed over slope to protect soil and slow water movement	• provides bank protection and encourages vegetation regrowth • uses readily available, natural materials • can be conducted at time of construction.	• least suitable during active growing season • construction is labour intensive • may accelerate erosion if not properly installed	• can be combined with armouring and other methods
Silt fences (Dwg. No. 17)	• geotextile fence secured with steel rods on banks • may be used in conjunction with other techniques (e.g., straw bales)	• minimized slopewash into watercourse • easy to install	• difficult to work around • requires periodic maintenance	• temporary measure
Slope terracing	• benches are constructed on a slope to reduce overall slope load and gradient	• reduces overall slope and gradient to minimize the potential of slope failure • aids in revegetation	• requires additional work area • expensive and labour intensive	• appropriate on constructed slopes where slope stability is more important than natural contours • not appropriate for most crossings
Live pole drains (Dwg. No. 21)	• bundles of willow branches securely tied partially buried in line with the fall line	• provides natural drainage conduit • eventual establishment of willows helps stabilize soil and reduces water transport	• labour intensive • only applicable in certain circumstances	• not appropriate for steep slopes and/or large volumes of water • not appropriate for stabilization of slumping areas
Restoration of drainage channels	• removal of excess spoil from drainage channel to maintain natural hydrology	• maintains natural channel and vegetation patterns • minimizes changes to downstream river users and potential aquatic habitat	• reduced storage area for spoil at drainage may require additional adjacent areas • lost material inadvertently adds to siltation	• appropriate for minor drainages which may not be flowing during construction

Table 5.1 Erosion Control Techniques, Cont'd

Technique	Description	Advantages	Disadvantages	Comments
III. POST CONSTRUCTION PHASE – FINAL CLEAN-UP				
Revegetation & cover crop	• seed by broadcasting, harrowing or drilling with a suitable mix of species • utilize a quick-growing annual or biannual to establish ground cover	• establishes a root mat and vegetation layer to reduce soil erosion by wind and water • cover crop will establish before permanent cover	• requires some time to establish a root mat and ground cover • native seed may be expensive or unavailable • poor quality seed mix may introduce noxious weed species • vegetation may require extensive efforts before establishing	• verify seed mix composition and quality with appropriate regulatory agencies prior to application • fertilizers and / or organic mulch may or may not be recommended
Organic matting/mulch	• paper or wood fibre spread by hand or by hydro-spray equipment to supplement soil organics	• provides long-term plant nutrition • improves overall quality of soil • if slope is seeded first, mulch provides cover and retains moisture	• mulch and application method may be expensive • access for equipment may be restricted • requires special materials • may wash-off during periods of heavy rain if a tackifier is not added	• may be needed on exposed mineral soil slopes to establish an organic layer • recommended for long-term revegetation projects • recommended for poor quality soils with or without a fertilizer
Rollback	• spread small diameter timber and slash over right-of-way and walk down with tracked equipment	• provides micro-habitats for water and seed catchment • slows surface water and wind minimizing erosion • may also incorporate natural seed as well as organic material	• slash volumes may be limited and salvage of merchantable timber may be required • may limit operations and maintenance access • may require extra right-of-way to permit storage during construction • may accelerate erosion if rollback is too large and not properly walked down	• may be incorporated with most other forms of erosion control • not to be placed in watercourses • recommend seeding after walking down rollback

6 Habitat Mitigation and Compensation

DFO's *Policy for the Management of Fish Habitat* (1986) provides a comprehensive framework for the conservation, restoration and development of fish habitats that contribute directly or indirectly to a fishery or potential fishery. Its long-term objective is to achieve an overall net gain in the productive capacity of fish habitats by conserving the current productive capacity of habitats ("no net loss"), restoring damaged fish habitats and improving and creating fish habitats. Other federal, provincial and territorial legislation, strategies, policies and guidelines also provide guidance to proponents.

Proponents are frequently confused about the distinction between mitigation and compensation. Habitat 'mitigation' is undertaken as a normal part of water crossing construction to prevent impacts on fish habitats and biota. In all cases, the first preference is to avoid potential effects on aquatic and riparian habitat, generally by modifying the route or crossing method. Where this is not possible, the next priority is to reduce potential negative effects through appropriate mitigation measures. These mitigation measures may include changes to project design and timing, environmental protection measures applied during construction, and restoration of riparian, bank and instream habitat disturbed by construction activities.

Habitat 'compensation' is undertaken by proponents to achieve "no net loss" where crossing activities could cause a HADD. The need for compensation is determined as part of the *Fisheries Act* authorization process. Compensation is described more fully in Section 6.1 below.

Riparian, bank and instream habitat restoration and enhancement techniques are summarized in Section 6.2 below. Restoration' is undertaken to restore ecological function lost as a result of disturbance. 'Enhancement' is undertaken to improve the productive capacity or function use of habitat. Restoration and compensation techniques may be applied for both mitigation and compensation purposes.

6.1 Compensation

According to the *Policy for the Management of Fish Habitat* (DFO 1986), compensation is "the replacement of natural habitat, increase in the productivity of existing habitat, or maintenance of fish production by artificial means in circumstances dictated by social and economic conditions, where mitigation techniques and other measures are not adequate to maintain habitats for Canada's fisheries resources". Cash in lieu of compensation is not acceptable.

Compensation is the least preferred option for addressing effects on fish habitat and is only considered when adequate mitigation is impossible or impractical. In these cases, where HADD is likely to occur (typically <10% of crossings reviewed by DFO), a proponent should request a Subsection 35(2) Authorization from DFO. The proponent is within its legal rights to proceed without getting this authorization. However, should this happen and HADD results, the proponent is liable to prosecution under the *Fisheries Act* if an Authorization is not in place.

The Subsection 35(2) Authorization allows a proponent to proceed under prescribed conditions, including the need to achieve "no net loss" by compensating for adverse effects on fish habitat. However, even though a proponent may be willing to undertake compensation, issuance of a Subsection 35(2) Authorization with compensation specified is the least preferred option and may not be acceptable for particularly valuable fish habitat. Authorizations will not normally be issued until adequate compensation measures are specified. Compensation measures may be set out directly in the Subsection 35(2) Authorization via reference in the Authorization or through legal agreement between the proponent and DFO. All costs associated with compensation are the responsibility of the proponent.

Proponents should consult with DFO and as necessary, provincial or territorial representatives, before developing compensation measures to confirm that mitigation is not possible and that compensation is an acceptable option. Proponents will also need to demonstrate that proposed compensation measures are technically and economically feasible and appropriate for each crossing requiring an Authorization.

6.1.1 Compensation Plans

Any instruction, action, intervention, construction or undertaking to offset an unmitigated impact to fish habitat is considered an effort towards compensation. Habitat compensation is intended to improve physical, chemical, or biological factors that are limiting habitat capability. This includes replacing damaged habitat with newly created habitat, increasing the productive capacity of existing natural habitat, or least preferably, maintenance of fish production by artificial means. These must be identified on a crossing-by-crossing basis by the proponent, in consultation with technical specialists, as well as provincial, territorial and federal authorities. Local fisheries management plans should also be used, where they exist, to help determine appropriate compensation options.

A compensation plan is usually submitted by the proponent as part of a development proposal. The plan ideally includes: type, location and extent of habitat to be affected; type, location and extent of compensatory habitat; the results to be achieved; monitoring to be undertaken; how success will be measured; and measures to be taken if success is not achieved.

6.1.2 Habitat Compensation Options

DFO (1999) provides the following hierarchy of preferences to compensate for affected habitat:

- create or increase the productive capacity of similar habitat (**like-for-like**) at or near the development site within the same ecological unit (*e.g.,* gravel placement; instream, bank and riparian habitat enhancement; removal of permanent fish passage obstructions for same species);

- create or increase the productive capacity of different habitat (**unlike**) in the same ecological unit (*e.g.*, gravel placement; instream, bank and riparian habitat enhancement; watershed restoration; removal of permanent fish passage obstructions);
- create or increase the productive capacity of a different ecological unit (**different**); and,
- artificial propagation (the least desirable option).

An ecological unit is defined as "populations of organisms considered together with their physical environment and the interacting processes amongst them." The ecological value of the existing habitat must be considered before moving down the hierarchy of compensation options.

The selection of the most appropriate option or options will depend on the existing watershed conditions, life history of the species affected, factors limiting habitat productivity and technical feasibility and long-term success of restoration and enhancement options. Proponents should consult with provincial, territorial and federal authorities, technical specialists and knowledgeable public representatives to identify appropriate compensation opportunities in or near the affected watercourse. It is important to take into consideration the regional fisheries management priorities or goals that may apply to the affected watercourse.

While proponents are responsible for achieving "no net loss", in some situations there may be advantages for DFO and/or its partners to complete additional measures that would result in net gain of productive capacity at the habitat compensation site by taking advantage of background information and logistical support. An example would be where an area was identified as having potential for significant habitat enhancement that would be far in excess of the requirements to meet "no net loss".

Same Habitat in Same Ecological Unit

DFO's preference is to provide for replacement of the affected habitat with similar habitat as close as possible to the affected area. This is based on the assumption that the supply of suitable habitat ultimately limits fish populations and that like-for-like compensation maximizes the potential for achieving "no net loss", without actually requiring the comparison of productive capacity before and after pipeline construction. In some situations it may not be possible to accept anything other than like-for-like compensation if the importance of the habitat being compensated for is too great.

Habitat at or near the development site can be restored, enhanced or created using riparian, bank and instream techniques discussed in Section 6.2. The selection of a particular technique depends largely on the existing site conditions including life history, stream hydrology, bank stability, icing conditions, soils, surrounding vegetation and reasons for limited productive capacity or observed damage. It is also necessary to understand how habitat will function once work is completed, the maintenance requirements of any structures, the life expectancy of materials used and any problems that could be created. This will help minimize future costs and impacts.

Year-round or seasonal habitat can be created by removing obstructions that prevent access to suitable spawning, rearing, or overwintering habitat. These include old, improperly installed or failed culverts, natural barriers, and debris dams. Channel modifications and gravel placement can be used to create new spawning, incubation and rearing habitat with suitable substrate and flow conditions. Rearing and feeding habitat can be created by installing bank and instream structures that create overhead and lateral cover.

Note however that experience has shown that site-specific projects are much more likely to yield only short-term results, create habitat at the expense of other areas, or fail altogether, than projects that consider the entire watershed. Measures that deal directly with fundamental problems in catchments or watersheds are most beneficial over the long-term.

Different Habitat in Same Ecological Unit

In situations where site-specific issues are well understood, limitations to productive capacity are known, or local management plans provide clear objectives for the fishery, alternative measures lower on the hierarchy may be most appropriate.

For example, a portion of wetland feeding habitat supporting minnow species will be destroyed. However, according to documentation in the local fisheries management plan, this type of habitat is in reasonably abundant supply. In consideration of the fisheries plan objectives, a preferred compensation option might therefore be to enhance a nearby gravel spawning habitat, since it is known to be in limited supply for another species. In many cases, riparian enhancement will be equally or more beneficial than instream habitat enhancement. This may justify unlike compensation.

In other situations, moving down the hierarchy may present a better opportunity for maximizing the amount of habitat gained, particularly where there are known limitations (or bottlenecks). As an example, riparian restoration may be equally or more beneficial than instream habitat enhancement in degraded watersheds. Allowances can be made for these situations, at the discretion of DFO.

The productive capacity of existing habitat at or near the development site can be increased by measures such as: corridor fencing to allow riparian vegetation recovery; instream, bank and riparian habitat enhancement using structures described in Section 6.2; and road deactivation and rehabilitation to control sediment loading. These same measures can also be used to improve habitat in a different ecological unit if opportunities are not available near the development site.

Different Ecological Unit

In the event that habitat restoration or enhancement opportunities do not exist in the same catchment or watershed, proponents may be asked to identify techniques that will improve habitat in another ecological unit. The techniques summarized in Section 6.2 would also be applicable in this case.

Several cumulative effects management measures have been implemented for compensation. These include stewardship or community watershed programs that deal with non-point water quality concerns; riparian fencing programs on grazing lands; and radio-telemetry studies to help quantify productive capacity (*e.g.*, location and extent of critical spawning or overwintering habitat). One challenge with these different approaches is the need to quantify both loss and compensation offsets.

Restoration of Orphan Sites

The clean-up or restoration of altered, disrupted, or degraded habitats for compensation purposes is considered to be a useful practice and is generally encouraged. This option is applicable to any level in the compensation hierarchy. This may be considered for sites with no known responsible owner, where the disturbance occurred with an outdated legal or policy framework, and where legal and liability agreements can be reached. Compensation should be consistent with local fish management plans where they exist, and partner agency objectives should be considered.

Restoration as compensation is not appropriate at "non-orphaned sites," as these should be cleaned up by the responsible party/owner. Neither should it be considered when government is investing in or financing the cleanup.

Habitat Banking

Habitat banking occurs when a proponent creates or improves fish habitat for future use as compensation (*i.e.*, prior to an authorization being issued). The location and design of a habitat bank must first be approved by DFO and proponents must provide data describing the "before" conditions before habitat banking work is begun.

Habitat banking sites should be worthy of restoration or enhancement, land ownership and access should be clear, and all required permits must be in place. Habitat banks are useful in situations where a proponent needs to compensate for several small HADDs, and few compensation options exist at the site(s). Habitat banking may have the benefit of requiring smaller replacement ratios, since effectiveness is already known. During the time between the creation of the new habitat and its use as compensation, fish benefit from the existence of the habitat bank and a net gain of productive capacity occurs.

The creation of a habitat bank does not "pre-approve" any future HADDs as all projects will be reviewed on their own merits. The use of a habitat bank is considered at the request of the proponent, but all on-site compensation options must be explored before using the habitat bank. A habitat bank must be evaluated immediately prior to its use as compensation to ensure that the bank is functioning properly and determine its value relative to original conditions. If only a portion of the bank is to be used in any given year, it is important to document what part of the bank is still available for use as future compensation. If the productive capacity of any bank or part thereof increases after it has been used as compensation, this increase will not be considered additional banked habitat.

Measures of Last Resort

Artificial propagation, deferred compensation, and restoration of chemically contaminated sites are measures of last resort and only where they can effectively achieve "no net loss". Given the risk associated with each of these approaches, approval of a DFO senior regional manager is required.

Artificial propagation is a capital- and maintenance-intensive method to replace a natural habitat's productive capacity and is by far DFO's least preferred option. It is generally not accepted in cases where natural habitat is lost and will only be considered in rare cases where DFO determines that it is in the public interest.

Deferred compensation refers to compensation that is done at some point in the future. For example, there may be no immediate opportunity to compensate for a project in a pristine area. Deferred compensation requires that a detailed strategy and plan be included in the authorization. This approach may require larger replacement ratios to offset the extended loss of productive capacity during the time that compensation is deferred.

6.1.3 Determining the Amount of Compensation Required

The amount of compensation must be determined based on the residual net loss of productive capacity after relocation, redesign and mitigation have been taken into consideration. Compensation usually requires a compensation ratio that exceeds 1:1 to ensure that "no net loss" occurs, allowing for time lags and uncertainty of success. Lower ratios are acceptable where compensation works are completed and functional before habitat loss occurs. In most cases, replacement ratios increase as the proponent moves down the compensation hierarchy and certainty of "no net loss" decreases. Appropriate scientific tools are generally used to determine appropriate compensation ratios (*e.g.*, Minns 1995, 1997; Minns *et al.* 1995, 1996; Portt *et al.* 1999).

6.2 Mitigation and Compensation Techniques

Habitat protection, restoration and enhancement of aquatic and riparian habitat may be conducted in conjunction with pipeline crossings to avoid or compensate the effect of construction activities. Riparian habitat refers to the unique vegetation community found between a waterbody and the surrounding upland. This vegetation develops on banks, floodplains and wetlands with soils that are wet during some portion of the growing season (Meehan 1991). These riparian areas support diverse migratory bird, wildlife and plant communities and are an important component of aquatic habitat because they provide food, shade and cover and help stabilize streambanks.

Habitat restoration and enhancement is most frequently undertaken in sensitive streams with species that are rare, at risk, or of recreational, economic, subsistence, or scientific interest. A variety of protection, restoration and enhancement techniques are available and qualified specialist advice should be obtained to identify what effects could occur, what mitigation is required and to select the most appropriate method or combination. Specific procedures are described for bank and riparian habitat in Section 6.2.1 and instream habitat in Section 6.2.2. The selection of a particular technique depends largely on the existing site conditions including stream hydrology, bank stability, icing conditions, soils, surrounding vegetation and reasons for observed damage or limited productive capacity.

It is also necessary to understand how the restored watercourse will function once work is completed, the maintenance requirements of any structures, the life expectancy of materials used and any problems that could be created. This will help ensure that aquatic and riparian habitat is protected or enhanced in a way that minimizes future costs and impacts.

Considerable cost savings can be realized by using equipment and local materials that are already available at the time of construction. In some cases however, rehabilitation and enhancement work will need to be done at a different time than pipeline installation.

Ideally, proponents should consider their long-term development plans and identify opportunities for sequential or co-operative restoration and enhancement programs within a watershed. Experience has shown that site-specific projects are much more likely to yield only short-term results, or fail altogether, than projects that consider the entire watershed.

Where work is not undertaken by professionals under an established Code of Practice, proponents should consult with the local or regional fisheries biologist, regional DFO representative, other regulatory agencies, qualified technical specialists and public representatives to identify the most appropriate mitigation and compensation procedures. In all cases, proponents must ensure that necessary approvals are obtained for proposed protection, restoration and enhancement work.

6.2.1 Bank and Riparian Habitat Restoration and Enhancement

Bank and riparian habitat is directly affected by grading and clearing, and may also be indirectly affected by changes in surface and groundwater flow patterns, or through trampling, grazing and erosion where animals and recreational users utilize the right-of-way. Disturbance of riparian and bank areas can result in direct and indirect effects on water quality, water temperature, channel patterns, as well as fish and wildlife habitat availability and productivity.

Restoration or stabilization of stream banks may be required to minimize erosion or undertaken to restore or enhance nearshore fish habitat for compensation purposes. Stream bank erosion is a concern where sediment is deposited in downstream habitats such as spawning, rearing and overwintering areas. Special care should be exercised in stabilizing the outside bends of streams, since such areas are subject to greater erosion pressures. The following additional issues or concerns are associated with water crossing construction in riparian areas:

- riparian habitat may be directly affected by siltation resulting from pipeline construction activities; and
- water quality may also be indirectly affected by changes in surface and groundwater flow patterns resulting from pipeline construction, or through trampling, grazing and erosion where animals and recreational users utilize the right-of-way.

A variety of site-specific and watershed management techniques are available to restore or enhance riparian and bank areas. Site-specific techniques are summarized in **Table 6.1**; appropriate Drawings are also referenced. Proponents should consult with technical specialists and public representatives to identify appropriate watershed restoration and enhancement procedures such as riparian fencing or public awareness.

At typical watercourse crossings where the banks are graded to a low angle, nearshore rearing and holding habitat is limited following completion of construction. Natural materials such as boulders (riprap and rock armouring), root balls and trees placed or anchored on streambanks can enhance nearshore habitat by providing hiding and resting places for juvenile and adult fish. The objectives of these methods are to provide economical, short- to long-term bank stabilization structures with a natural appearance and relatively low maintenance requirements.

Methods that increase the angle of the bank can also be installed. These include: fibre and grass rolls; logwalls and cribwalls; overhangs and lunker structures; brush layering, matting and bundles; tree revetments; and shrub planting and transplants. The objectives of these methods are to increase nearshore depth and encourage development of self-sustaining, overhanging plant cover. Many of these structures have a limited life span, so they should be designed to encourage natural bank development. Biodegradable products should be used whenever possible.

A long-term monitoring and maintenance program should be initiated to maintain the integrity of riparian and bank restoration and enhancement projects (Section 7.2).

6.2.2 Instream Habitat Restoration and Enhancement

The key characteristic of productive instream habitat is diversity. When properly used, instream structures and techniques can restore or enhance important or critical features such as spawning and food producing areas, cover and overwintering habitat. Spawning areas must provide a suitable environment during the egg laying, incubation and fry emergence periods. Food producing areas have substrate, depth and flow conditions that support aquatic invertebrates and forage fish. Instream cover provides fish protection from high current velocities and predators. Overhanging vegetation, undercut banks, submerged objects, depth and water turbulence provides cover (Wesche 1985).

A variety of site-specific and watershed management techniques are available to restore or enhance instream habitat. A general discussion of site-specific instream restoration and enhancement techniques is provided below. Additional information is summarized in **Table 6.2** and Drawings are provided in Appendix A. Note that care must be taken to select suitable techniques, particularly for instream enhancement. Experience has shown that installation of ‘enhancement’ features that do not adequately reflect natural waterbody hydrology or ecology can create unwanted and undesirable long-term effects.

Removal of permanent obstructions to fish passage is an effective technique used to compensate for HADD. Instream barriers and debris can be natural (beaver dams, rocks, woody debris, falls) or man-made (garbage, culverts). Removal of barriers to fish movement can restore watershed connectivity by providing access to suitable spawning and rearing areas. Instream debris and barriers can slow stream flow, causing sediment deposition, increased water temperature and erosion where the debris redirects stream flow. Since natural barriers and debris also provide cover and overwintering habitats, technical specialists should be involved to determine whether these structures are beneficial or damaging habitat. Care should also be taken to ensure that removal of barriers or debris does not result in unintended effects on downstream habitat.

Bank rehabilitation and enhancement measures such as boulders, root balls, tree revetments, cribwalls and overhangs described in the previous section also provide or improve instream habitat for juvenile and adult fish. Logs, boulders, root balls and trees can also be placed in the stream channel to provide lateral and overhead cover and rearing habitat, establish meanders or pools and protect eroded banks.

Table 6.1 Bank Restoration and Enhancement

Description	Advantages	Disadvantages	Comments
BOULDER PLACEMENT AND BANK ARMOURING (Dwg. No. 23)			
• Riprap or boulders placed on bank. • Can be combined with geotextiles to prevent undercutting and erosion.	• Stable at almost all flow levels. • Very durable; low upkeep. • Simple to install. • Provides instream cover and macro-invertebrate habitat.	• Requires heavy machinery. • Unnatural appearance. • Suitable material may not be readily available.	• Suitable for all watercourses with coarse bottoms. • Proper placement is critical to avoid undesired effects. • Can be used in combination with most other techniques.
TREE REVETMENTS AND ROOT BALLS (Dwg. Nos. 24, 32)			
• Clean root balls or woody material anchored into streambanks. • Conifers anchored into streambanks with branches intact and butt end upstream.	• Installation is relatively easy and inexpensive. • Provides immediate cover and rearing habitat, bank stability, and sediment collection. • May also be used to improve channel conditions (pool-riffle ratio; meanders) and protect eroding outside bends. • Natural appearance.	• Can be washed away or damaged by high flows and ice. • May not provide long-term stability or habitat. • Tree revetments may be considered unsightly as needles fall off. • Stabilization of opposite bank may be required.	• Most suitable in low to moderate gradient watercourses. • Trees should be largest available. • Can be used in combination with rock clusters for additional protection.
GABIONS AND SHEET PILING (Dwg. No. 25)			
• Rock-filled wire or plastic baskets anchored into streambank. • Sheet piling anchored in streambank.	• Provides long-term stability for bank and slope toe. • Can be used on steep slopes or where suitable riprap material is not available. • Simple to construct.	• Expensive and labour intensive. • Usually requires heavy machinery. • Baskets can deteriorate, leaving unsightly and unsafe wire ends. • Difficult to repair if undermined. • Unnatural appearance. • Susceptible to erosion at upstream end if improperly installed.	• Riprap generally preferred on shallow to moderate slopes. • Appearance can be enhanced with sod or superficial brush / shrub layering.
FIBRE COIR LOGS AND GRASS ROLLS (Dwg. Nos. 26, 27)			
• Fibre coir logs - biodegradable logs constructed of interwoven coconut fibres. • Grass rolls - clumps of sod bound tightly into a sausage shape with burlap. Holes cut to expose shoots.	• Provides temporary stability for bank and slope toe. • Provides growth medium. Do not require heavy equipment for installation.	• Susceptible to dislodging. May not provide long-term stability or habitat. • Labour intensive.	• Most suitable as temporary solution to allow vegetation to become established. • Most suitable for small waterbodies with low banks. • Slow, low gradient watercourses

Table 6.1 Bank Restoration and Enhancement, Cont'd

Description	Advantages	Disadvantages	Comments
LIVE STAKING AND TRANSPLANTS (Dwg. No. 28)			
• Planting of individual dormant cuttings. • Transplanting individual plants or sod from immediate area or nursery stock.	• Uses readily available, native materials. • High success rate with proper species and procedures. • Transplanted shrubs and trees can provide immediate cover. • Provides both aquatic and terrestrial habitat.	• Unsuitable for dry soils. • Large projects may require material from multiple sites. • Heavy machinery required to transplant large shrubs and trees. • Suitable nursery stock may not be available or economic. • Many transplants do not survive as they are eaten by wildlife and cattle.	• Cuttings should be dormant; most successful in early spring. • Watering can increase survival. • Stakes may be used to anchor brush bundles, brush mattresses and erosion control blankets. • Obtain permission if transplants are to be taken from off right-of-way.
LOGWALLS AND CRIBWALLS (Dwg. No. 29)			
• Logwall - a log retaining wall installed to create a vertical bank. Held in place with vertical pilings. • Cribwall - a logwall with a system of offset cross logs that anchor the structure.	• Maintains nearshore stream depth, bank slope and provides erosion control. • Less expensive than rock structures. • Long-term protection if well maintained. • Provides some overhead cover for fish. • Will deteriorate over time to restore “natural” bank.	• Requires heavy machinery and ongoing maintenance. • Somewhat artificial appearance. • Time consuming and labour intensive. • Structure deteriorates over time (e.g., 3 years untreated wood, 12 years treated wood).	• Most suitable in watercourses with eroding banks, stable channel and flows with low to moderate gradient. • Structure will last longer if all wood is submerged. • Can be used in series.
BRUSH LAYERING (Dwg. No. 30)			
• Fill slopes consisting of alternating layers of soil and live branches. • Brush layers of criss-crossed branches angled into slope. • Can be combined with geotextiles on steep slopes.	• Provides erosion control and overhanging cover almost immediately. • Uses readily available, natural materials. • Can be conducted at time of construction. • Provides terrestrial habitat.	• Least suitable during active growing season. • Construction is labour intensive.	• One of best techniques for stabilizing slopes and streambanks. • Can be combined with armouring and other methods.
LIVE SILTATION			
• bury branches along high water mark and backfill with rock	• Promotes silt entrapment along bank. • Produces bank protection and overhead cover. • Relatively easy to construct.	• Least suitable during active growing season. • Construction is labour intensive.	• Can be combined with other erosion control measures.

Table 6.1 Bank Restoration and Enhancement, Cont'd

Description	Advantages	Disadvantages	Comments
BRUSH BUNDLES, FASCINES OR WATTLES			
• Bundles of live cuttings tied to produce sausage shaped bundles. • Planted in shallow trenches anchored with wooden or live stakes.	• Can be used to direct or slow water movement and encourage vegetation growth on bank. • Don't require heavy equipment for installation.	• Provides very limited structural stability. • Least suitable during active growing season. • May rot and require extensive maintenance. • Construction is labour intensive.	• Can be combined with other erosion control measures.
BRUSH MATTING			
• Mattress-like layer of branches placed over slope to protect soil and slow water movement.	• Provides bank protection and encourages vegetation regrowth. • Uses readily available, natural materials. • Can be conducted at time of construction.	• Least suitable during active growing season. • Construction is labour intensive.	• Can be combined with armouring and other methods.
EXCLUSION FENCING			
• Installation of fences to exclude livestock and vehicles.	• Prevents trampling, rutting and erosion. • Allows natural growth or recovery of riparian vegetation and banks. • Most effective technique to restore banks or watercourses damaged by livestock.	• Relatively expensive and labour-intensive. • Requires landowner agreement. • Ongoing inspection and maintenance.	• Fence should be set back far enough to allow for vegetation growth and lateral channel movement. • Livestock watering and crossing sites may be necessary.

Table 6.2 Instream Habitat Restoration and Enhancement Techniques

Description	Advantages	Disadvantages	Comments
INSTREAM COVER Rock Clusters (Drawing No. 31)			
• Boulder groupings placed on streambed.	• Simple and effective technique to provide overhead and lateral cover and rearing habitat. • May also be used to improve channel conditions (pool-riffle ratio; meanders) and catch granular materials. • Natural appearance. • Inexpensive materials.	• Suitable material may not be readily available. • Requires heavy equipment. • Improper placement may cause bank erosion by altering streamflow dynamics.	• Proper placement is critical to avoid undesired effects. • Can be used in combination with most other techniques.
INSTREAM COVER Tree Revetments and Root Balls (Drawing Nos. 24, 32)			
• Clean root balls anchored into streambanks or streambed. • Conifers anchored into streambanks with branches intact with butt ends upstream.	• Installation is relatively easy and inexpensive. • Provides immediate cover and rearing habitat, bank stability, and sediment collection. • May also be used to improve channel conditions (pool-riffle ratio; meanders). • Natural appearance.	• Can be washed away by high flows and ice. • May not provide long-term stability or habitat. • Tree revetments may be considered unsightly as needles fall off. • May require stabilization of opposite bank.	• Most suitable in low to moderate gradient watercourses. • Can be used in combination with most other techniques.
INSTREAM COVER Submerged cover (Drawing No. 33)			
• Submerged log or log slab secured in watercourse to provide cover. • Submerged artificial cover such as swamp weights or irrigation chute.	• Inexpensive and easy to install or adjust. • Can be used as temporary or permanent structure. • Logs have natural appearance.	• Not effective in watercourses with wide fluctuations in flow. • Can catch debris if not installed properly. • Artificial cover has unnatural appearance.	• Most suitable in small to medium sized watercourses with low to moderate gradient and not subject to extreme flooding or ice damage. • Can be used in combination with most other techniques. • Natural cover materials preferred.
BANK COVER Logwalls and Cribwalls (Drawing No. 29)			
• Logwall - a log retaining wall installed to create a vertical bank. Held in place with vertical pilings. • Cribwall - a logwall with a system of offset cross logs that anchor the structure.	• Maintains nearshore watercourse depth. • Less expensive than rock structures. • Long-term protection if well maintained. • Provides some overhead cover for fish. • Will deteriorate over time to restore “natural” bank.	• Requires heavy machinery and ongoing maintenance. • Somewhat artificial appearance. • Time consuming and labour intensive. • Structure deteriorates over time (e.g., 3 years untreated wood, 12 years treated wood.	• Most suitable in watercourses with eroding banks, stable channel and flows and low to moderate gradient. • Structure will last longer if all wood is submerged. • Can be used in series.

Table 6.2 Instream Habitat Restoration and Enhancement Techniques, Cont'd

Description	Advantages	Disadvantages	Comments
BANK COVER Bank Overhangs (Drawing No. 34)			
• Artificial overhang of concrete, timber, or gabion baskets tied into streambank. • Can be covered and revegetated.	• Provides stable overhead cover and offers some bank protection. • Confines streamflow. • Natural appearance once revegetated.	• Construction is labour intensive and can be costly. • If current is diverted, downstream bank stabilization may be necessary. • Not durable in large watercourses. • Can be damaged by ice.	• Most suitable in watercourses with stable channel and flows and low to moderate gradient. • Structure will last longer if all wood is submerged. • Can be used in series or placed opposite deflectors to scour out a pool under the cover. • Should not extend beyond natural stream bank to prevent downstream erosion.
BANK COVER Wing Deflectors (Drawing Nos. 35, 36)			
• Triangular structures made of rock or logs that create a narrower, deeper channel with increased flow velocity.	• Can help keep downstream areas free of sediments. • Can produce cover by scouring pools and creating undercut banks.	• Can be costly, and require heavy equipment. • Can cause erosion problems and bank instability. Downstream bank stabilization may be necessary. • Unnatural appearance.	• Proper placement is critical. • Most suitable in watercourses with low to moderate gradient, especially wide, slow flowing reaches. • Can be used in series or combination with cover on opposite bank. • Contact DFO to determine if *Fisheries Act* Authorization is required.
BANK COVER Groynes (peninsular deflectors) (Drawing No. 37)			
• Peninsular structures made of rock that are used to redirect flow.	• Can help keep downstream areas free of sediments. • Can produce cover by scouring pools and creating undercut banks. • Provides fish habitat. • More effective then continuous bank protection.	• Can cause erosion problems and bank instability. Downstream bank stabilization may be necessary. • Unnatural appearance. • During high flows, results in severe erosion downstream of groyne.	• Proper placement is critical. • Most suitable in watercourses with low to moderate gradient, especially wide, slow flowing reaches. • Can be used in series or combination with cover on opposite bank. • Contact DFO to determine if *Fisheries Act* Authorization is required.

Table 6.2 Instream Habitat Restoration and Enhancement Techniques, Cont'd

Description	Advantages	Disadvantages	Comments
OVERPOUR STRUCTURE Dams (Drawing Nos. 38, 39)			
• Low profile dams constructed of rock or logs. • Log structures include single log dam, K-dam, wedge dam, and plank dam.	• Provides resting habitat and plunge pools in high gradient waters. • Can retain gravel. • Aesthetically appealing. • May increase dissolved oxygen.	• Construction is labour intensive and relatively expensive. • May block sediment transport, filling in area above dam. • Unstable at high flows. • Failure and high liability.	• Proper placement is critical. • Moderate to high gradient watercourses with stable flows where significant impoundment will not occur. • Contact DFO to determine if *Fisheries Act* Authorization is required.
OVERPOUR STRUCTURE V-Weir (Drawing Nos. 40, 41)			
• Log or rock structures placed in a V shape across the watercourse.	• Can create pool habitat, cover and retain gravel. • Economical.	• Can cause erosion problems and some bank instability. • Requires heavy equipment.	• Proper placement is critical. • Most suitable in small watercourses with low gradient. • Contact DFO to determine if *Fisheries Act* Authorization is required.
SUBSTRATE MANIPULATION Gravel Placement			
• Clean gravel placed on streambed. • Minimum depth is 1.0-1.8 m.	• Clean gravel may be used during construction for dams and crossing structures. • Economical.	• Temporary. • Suitable material may not be readily available. • Requires heavy equipment. • Over time, gravel may be easily washed downstream or filled with sediment.	• Most suitable in small to medium watercourses with low to moderate flow and low sediment load.
SUBSTRATE MANIPULATION Excavated Pool, Run (Drawing Nos. 42, 43)			
• Artificial pool or run excavated in streambed with heavy equipment.	• Immediate resting habitat and cover.	• Excavated areas fill easily with transported sediment from run-off. • Temporary. • Requires heavy equipment.	• Most suitable in small to medium watercourses with low sediment transport capability. • May be used in combination with bank cover or current deflectors. • Approval required.

Table 6.2 Instream Habitat Restoration and Enhancement Techniques, Cont'd

Description	Advantages	Disadvantages	Comments
SUBSTRATE MANIPULATION Gravel Cleaning			
• Cleaning of spawning gravel by vaccuuming, mechanical scarification or hydraulic flushing.	• Immediate improvement in gravel quality for spawning and aquatic invertebrates.	• Most techniques require heavy machinery. • Fine sediments washed downstream may degrade habitat and water quality. • Aquatic invertebrate production in cleaned area may decline. • Temporary.	• Employed primarily in spawning channels or lake tributaries. • Limited application in natural watercourses because of potential for downstream effects.
DAMS AND DEBRIS Debris Removal			
• Removal of rocks, trash or woody debris that are damming or blocking the stream channel.	• Can restore channel patterns and provide access to upstream spawning or rearing habitat.	• Can reduce habitat quality if poorly implemented.	• N/A
DAMS AND DEBRIS Culvert Repair			
• Repair or replacement of existing culverts that are barriers to fish movement.	• Can restore channel patterns and provide access to upstream spawning or rearing habitat.	• Constant inspection and maintenance may be necessary. • High maintenance.	• Repair or replacement can be effective compensation technique. Possible 'band-aid' solution if culverts are inappropriate in the first place.
DAMS AND DEBRIS Beaver Management			
• Permanent beaver dam removal or opening passages in dams during critical periods.	• Can provide access to upstream spawning or rearing habitat.	• Constant inspection and dam removal may be necessary. • High maintenance.	• Most beaver dams are best left in place. • Beaver dam removal requires approval in most provinces.

Current deflectors are one of the most commonly used structures to manipulate instream habitat. They are relatively inexpensive and easy to construct and can: be built from a variety of materials; be adapted to site conditions and a variety of stream sizes; be used in conjunction with other techniques; and fulfill more than one purpose. Deflectors can be built to: direct currents to desired locations; develop meander patterns; deepen and narrow channels; deepen pools and scour sediment; increase water velocities; keep flow out of side channels; encourage silt bar formation; maintain low water temperatures; and enhance pool-riffle ratios. Technical specialists should be involved to ensure that unwanted effects do not occur.

Current deflectors can be constructed of logs, rocks, boulders, gabions or various combinations of these materials. These structures are typically angled downstream and include triangular and peninsular shapes (wing deflectors and groynes, respectively). Structure height is generally determined from low flow conditions. Double-wing deflectors combining two current deflectors on opposite banks can also be used in larger streams to narrow the channel.

Low profile dams and weirs are multipurpose structures created from a variety of materials. Overpour structures are used to create pool habitat, raise water levels and collect and hold spawning gravel. They are most often used on small, high gradient streams and are relatively inexpensive, although construction is labour intensive. Their success depends on proper siting and construction; technical specialists should be involved to ensure that unwanted effects do not occur.

Substrate manipulation can be used in both warm- and cold-water habitats and includes placement or capture of suitable spawning materials and excavation of runs and pools. In streams with a natural bedload of granular spawning substrates, instream structures such as current deflectors, weirs and dams may be placed so that granular material is deposited and retained in suitable locations. Spreading clean gravel, especially when already used to construct dams for isolated watercourse crossings, can create spawning habitat if channel characteristics are appropriate. In streams with unstable flows or periodic flooding, catchment devices may be required to stabilize spawning substrates.

Proponents should consult with technical specialists and public representatives to identify appropriate watershed restoration and enhancement procedures. These include: road deactivation and rehabilitation; corridor fencing programs to protect waterbodies; sediment interception and retention; and public education programs to promote awareness of fisheries as well as fish habitat conservation and protection.

Instream structures have a limited life span and are susceptible to damage by floods and ice. A long-term monitoring and maintenance program should be initiated to maintain the integrity of restoration and enhancement projects and minimize unanticipated or unintended damage (Section 7.2). In addition, instream habitat restoration and enhancement may create an impediment to navigation. Before any structures are installed, proponents should contact TC to ensure no concerns exist or the correct approvals are obtained.

7 Monitoring Crossing Project Performance

In sensitive watercourses, or where there is concern regarding impacts on fish or fish habitat, specific watercourse crossing objectives may be specified prior to construction. As discussed in Section 1.3, proponents are also advised to develop corporate or project-specific watercourse crossing objectives for inclusion in environmental protection plans, bid documents and regulatory applications. These crossing objectives may be based on existing legislation, fisheries management objectives for the area, or discussion with appropriate regulatory authorities and could include measurable water quality values or biophysical criteria or thresholds. Construction-related objectives could include duration, location or quantity of instream and riparian construction activities.

Objectives will depend on the watercourse being crossed, the species and habitat present and the time of construction. For example, protection of spawning and incubating habitat will be of primary importance for a crossing proposed during the spawning period. In this case, objectives could specify appropriate flow levels and suspended sediment concentrations, or maintenance of desirable substrate characteristics during the spawning and incubation period.

Section 35 of the *Fisheries Act* refers solely to fish habitat, but DFO's *Policy for the Management of Fish Habitat* makes the link between habitat and productive capacity. Changes to productive capacity are not normally measured or estimated directly. Rather, the inferred change in productive capacity is based on an understanding of how physical, chemical and biological attributes describe habitat. Changes in these attributes are used as an indicator of changes in habitat and ultimately, productive capacity.

Guidance on performance attributes, criteria and objectives can be obtained from:

- existing water quality standards (*e.g.,* Canadian Council of Ministers of the Environment Water Quality Guidelines 1999);
- model outputs (*e.g.,* sediment dose models described in Anderson *et al.* 1996);
- construction monitoring programs; and
- specialist advice from aquatic scientists.

Once crossing objectives have been specified, construction inspection and monitoring and post-construction monitoring programs should be designed to evaluate crossing success (see Sections 7.1 and 7.2).

To identify opportunities where cost or risk can be minimized with no adverse biophysical effects, crossing success should be evaluated both after construction and after post-construction monitoring results are available. Ideally, all parties should be involved in these reviews, including: project managers; onsite inspection staff; environmental staff; contractors; technical specialists; and regulators.

7.1 Environmental Monitoring During Construction

7.1.1 Environmental Inspection

Environmental inspection of construction at watercourse crossings by the proponent is recommended on all watercourses that are rated as having medium or high sensitivity. Inspection during construction on low sensitivity water crossings may be incorporated as part of the construction inspection.

Environmental inspection should be performed to ensure that the mitigation measures warranted at the crossings are implemented in a manner that minimizes the adverse environmental effects of construction. Environmental protection planning is of little value if the protection measures are ignored or poorly implemented during construction. It is critical that inspection start prior to the initial right-of-way preparation to prevent any mistakes early in the construction sequence. Environmental inspectors should have the appropriate authority to take corrective action as warranted including suspending an activity until the contractor complies with approvals or until approval from the appropriate government agency is obtained.

Inspectors should be chosen on the basis of their understanding of environmental requirements, knowledge of construction techniques and ultimately, their ability to integrate the two in the field and under pressure. Inspectors who cannot practically apply their environmental training or deal with the contractors will not likely last long on a construction spread. Inspectors who have little environmental training may not make the correct decision under pressure as they may not have the academic knowledge required to support their decisions. Finally, inspectors need capable contacts in the office that can research or support their decisions when they need assistance in making a decision while in the field.

Roles of the inspectors include ensuring that the following is undertaken:

- all acts, regulations and permits are in place and followed;
- procedures and contingencies are in place including all equipment and back-up equipment;
- siltation and sedimentation are controlled along all segments of the watercourse;
- crossing is completed as quickly as possible; and
- the environment is protected.

Collection of monitoring data during construction allows effects on water quality, habitat, fish and other animals to be documented. This information can help to:

- provide feedback to construction staff;
- confirm the effectiveness of protection measures;
- fulfill legal requirements;
- provide evidence of compliance; and
- validate scientific predictions.

Over time, use of a standardized monitoring procedure will help develop a data set that can be used to validate impact predictions, improve predictive models and help select the most appropriate construction methods. One or more of the following environmental variables may be monitored during construction, depending on the concerns and crossing objectives:

- suspended sediment load before, during and after construction to provide feedback to construction personnel and document the zone of influence and changes in water quality;
- substrate composition before, during and after construction to document areas of sedimentation;
- biological monitoring, including abundance, density and community composition before, during and after construction;
- watercourse flows during construction to ensure that fish passage and minimum flows are maintained; and
- monitoring during blasting and diversion procedures.

The location and number of sampling locations will be a function of the anticipated zone of influence. This can be predicted using sediment deposition models or estimated based on the size and channel characteristics of the watercourse being crossed.

7.1.2 Suspended Sediment Load

Monitoring of suspended sediment load is the most common instream construction monitoring technique. This usually combines field monitoring of stream discharge and turbidity (a measure of transparency of the water column) with laboratory analysis of TSS and settleable solids concentrations. An empirical turbidity-TSS relationship is then derived, so that turbidity measurements can be used as an indicator of actual TSS and settleable solids levels (see Anderson *et al.* 1996). The presence of critical habitats may justify inclusion of additional sample sites, transects or other water quality parameters.

Established quantitative water quality guidelines for TSS and turbidity (*e.g.*, CCME 1999) are based on chronic exposure data and do not represent a realistic objective for short-term instream activities. This is because these long-term, low concentration standards may not be applicable to short-term high concentration events such as those associated with pipeline crossings. For this reason, some specialists have applied sediment-dose models to establish water quality objectives and evaluate actual effects. These models (*e.g.*, Newcombe and MacDonald 1991; Shen and Julien 1993; Anderson *et al.* 1996) predict effects on fish based on the duration and concentration of the sediment event, rather than a pre-established TSS/turbidity threshold.

A single suspended sediment load monitoring protocol has not been accepted due to the number of factors that affect sediment generation and transport and the influence of site-specific conditions. Qualified specialists should be involved to design a suspended sediment monitoring program, but the following discussion outlines some factors to be considered (see for example MacDonald and Bjornson 1993; Anderson *et al.* 1997; Clowater 1998).

Suspended sediment load monitoring should begin prior to construction and continue until water quality returns to control conditions and there is no potential for additional sediment plumes. Sampling immediately downstream of the crossing site (typically <100 m, the initial dilution zone) is important to document maximum sediment loads in the area with the highest potential for adverse effects. Depending on stream width, one or more samples should be taken at regular intervals across the watercourse. Surface samples are adequate in shallow watercourses (<0.5 m). Depth-integrated samples or samples taken from more than one depth may be required in deeper waters.

The first downstream site or transect should be regularly monitored prior to, during and immediately following, instream activities that have the potential to generate substantial sediment. Hourly sampling is appropriate immediately below the crossing site, but frequency can be reduced depending on the length of time of instream construction and when levels return to control conditions (*e.g.*, overnight). Sampling frequency may also be increased when instream activities are of short duration, or a specific sediment generating event is planned. It is recommended that a construction log be kept to allow suspended sediment load data to be compared to construction activities.

Additional samples will generally be required further downstream to monitor plume attenuation and determine the extent of the area affected by sediment release. Samples at these sites or transects may not warrant the same sampling intensity as the sampling sites immediately downstream of the crossing. However, supplementary samples should be added to document the start, peak and passing of sediment plumes.

Sampling should occur upstream of the crossing to provide "control" information on discharge and background levels of sediment load in the watercourse during construction. The upstream site should be located far enough upstream (typically >100 m) that it is not influenced by construction activity. Sampling frequency should be sufficient to detect natural variability in discharge and sediment load before, during and after construction.

7.1.3 Substrate Composition

Analysis of substrate composition downstream of the crossing site can be used to document the deposition of sediments due to construction, monitor the physical recovery of habitats following disturbance and help calibrate sediment transport models. A variety of techniques are available, including grab sampling, freeze-core sampling, sediment traps, visual surveys and direct measures of streambed porosity (see for example Weaver and Fraley 1991; Mudroch and MacKnight 1994; Anderson *et al.* 1996). The selection of the most appropriate monitoring program will depend on the program objectives and logistic considerations such as access, season, equipment availability and budget. Qualified specialists should be involved in program design.

Grab and freeze-core samples remove a small amount of the streambed for size distribution analysis in the laboratory. When samples are taken prior to and following construction at one or more sites, changes in the relative abundance of small diameter sediment particles can be determined and sediment deposition rates can be quantified.

Sediment traps are used to directly monitor the accumulation of small diameter sediment particles. Clean washed aggregates are used to fill a cylinder that is buried flush with the surface of the streambed. Traps are installed prior to construction activities along transects located both above and below the crossing site. They can be removed immediately after construction to assess deposition rates relative to the upstream controls, or be left in place to document sediment deposition and flushing over time.

In some watercourses, changes in channel and bottom profiles can be mapped at specified intervals along established transects. This method can be used to document changes in substrate composition following construction, identify areas of sediment accumulation and monitor recovery.

Standard visual survey or substrate description techniques can be used to compare substrate conditions prior to and after construction. The advantage of visual surveys is that they can be conducted quickly and relatively cheaply. However, they do not provide direct measures of sediment deposition and are affected by surveyor training and experience.

7.1.4 Biological Monitoring

The only way to directly measure effects on aquatic communities is to monitor aquatic invertebrate, fish, algae and riparian communities to detect reductions in biodiversity, abundance, or sensitive species and life stages. Due to the wide variety of habitats and techniques available, qualified specialists should be involved to design a practical and cost-effective biological program. The following discussion outlines some factors that should be considered (see for example Tsui and McCart 1981; Weaver and Fraley 1991; Davis and Simon 1995; Hauer and Lamberti 1996).

Aquatic invertebrates (which mainly consist of aquatic insects, mites, molluscs, crustaceans and worms) are the group of freshwater organisms most often used in aquatic biological monitoring (Resh *et al.* 1996). This is because aquatic invertebrates often live on the substrate, are sensitive to sediment deposition, are easy to monitor, are relatively immobile and are an important food source for fish and other riparian animals. Aquatic invertebrate monitoring can be used to document changes in substrate composition following construction, identify areas of sediment accumulation and track recovery.

Ideally, aquatic invertebrate sampling sites should be located above and below the crossing site in riffle habitats, where communities characteristic of streams and rivers are best represented, fauna diversity is highest and sensitive taxa are most likely to occur. Precise sampling locations should be selected to reflect the sediment plume mixing pattern and to ensure they have similar bottom substrate, depth, velocity, stream width, bank cover, etc. This will help to reduce natural sources of variability in the benthic samples and improve their effectiveness for assessing actual effects of pipeline construction. Benthic invertebrate monitoring data from control sites located upstream of the crossing will allow background natural variability in benthic invertebrate communities to be described.

Fish communities are sensitive, economically and socially important and respond to changes in habitat, water quality and human exploitation. Both community composition and the presence of sensitive species and life stages have been used to identify the responses of fish communities to disturbance. Since fish are relatively mobile and the effects of short-term sediment input are most likely to be sublethal, most surveys of fish communities are conducted prior to and following construction to evaluate effects on distribution, abundance, growth and species composition. Sampling may also be continued over time to evaluate subsequent recovery.

Algae that live on the bottom of waterbodies (periphyton) are at the base of the aquatic food chain and can be affected both directly and indirectly by suspended and deposited sediment. Periphyton have been used to evaluate effects on water quality because they have short life cycles, reproduce rapidly and, therefore, respond quickly to changes in water quality. Sampling design considerations are similar to those for benthic invertebrates, but fewer experienced specialists are available to analyze samples.

Monitoring of riparian habitat and biota may also be appropriate where riparian areas are identified as sensitive or unusual. A discussion of terrestrial monitoring techniques is beyond the scope of this document and qualified technical specialists should be consulted to help design a riparian monitoring program.

In some cases, use of more than one biological group or sampling technique may be required to fulfill legal requirements, evaluate effects on aquatic and riparian communities, or test predictions.

7.1.5 Monitoring During Blasting and Diversions

Specific monitoring requirements are generally specified in authorizations issued under Section 32 and/or Subsection 35(2) of the *Fisheries Act*. These typically include requirements to monitor fish distribution in the vicinity of the crossing prior to, during and following blasting and stream diversion activities as well as requirements to undertake and document fish salvage programs. Further measures may include monitoring to assess compliance and evaluation of effectiveness of fish habitat mitigation and/or compensation program.

Geophone or hydrophone monitoring may also be required to document pressure and impulse velocities during blasting.

7.2 Post-Construction Monitoring

A post-construction monitoring program should be based on specified watercourse crossing objectives and terms of authorizations, permits, licences or compensation agreements. Post-construction monitoring may be undertaken to:

- confirm that specific crossing objectives have been achieved;
- confirm the effectiveness of protection and compensation techniques;
- observe actual effects;
- observe recovery;
- determine the need for maintenance of structures and mitigative measures; and
- fulfill explicit mitigation and compensation requirements.

Typical post-construction habitat and biological monitoring programs last for at least one year and involve periodic monitoring of habitat, aquatic invertebrates, water quality, or fish species and life stage presence and numbers. Typically, measurements of predefined habitat parameters are combined with biological sampling at transects above and below the crossing site. Methods similar to those described above for construction monitoring are used in conjunction with upstream or nearby control areas so that the influence of natural ambient factors can be identified.

Post-construction monitoring should also include periodic inspection of erosion control and habitat restoration/enhancement structures so that necessary maintenance or replacement can be undertaken (Adams and White 1990).

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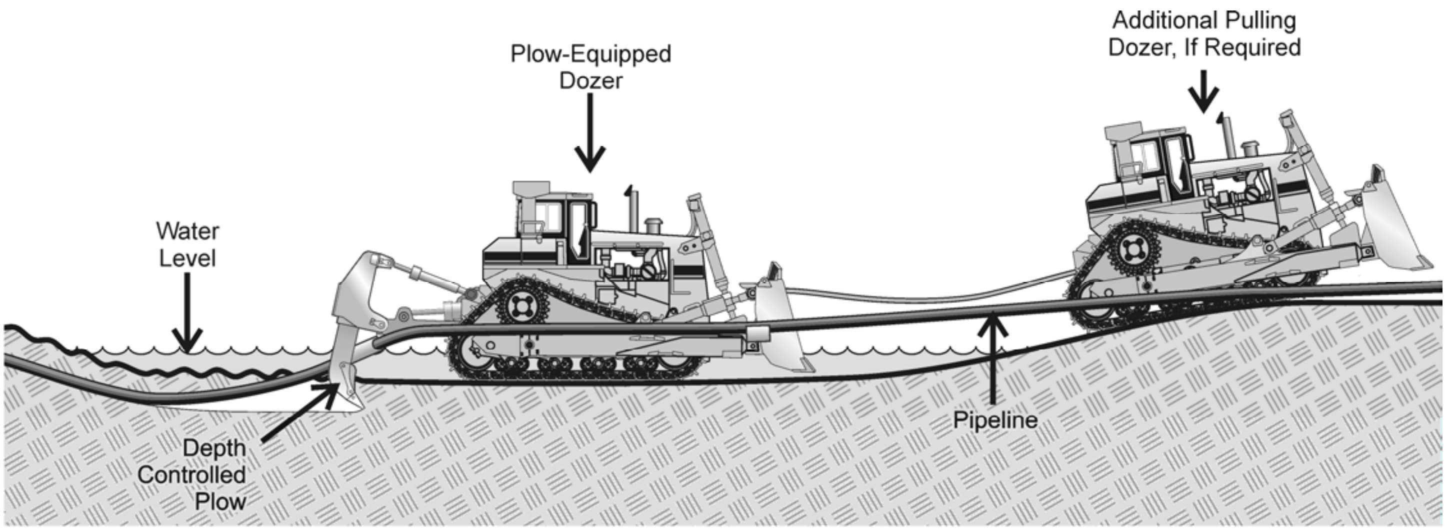
Appendix A Typical Watercourse Crossing Drawings

LIST OF DRAWINGS



PROFILE
(Not to Scale)

Notes:

1. Maintain a vegetation buffer at the crossing to the extent practical.
2. Install sediment and erosion control structures, as required.
3. Grade banks to allow access to watercourse by plowing equipment.
4. Complete construction of the instream pipe section.
5. Assist plow dozer with an additional pulling dozer, if warranted. Ensure adequate pulling power to plow through watercourse substrate is employed.
6. Regrade banks. Restore, stabilize and reclaim watercourse banks and approaches to as close to original grade as practical.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL PLOW

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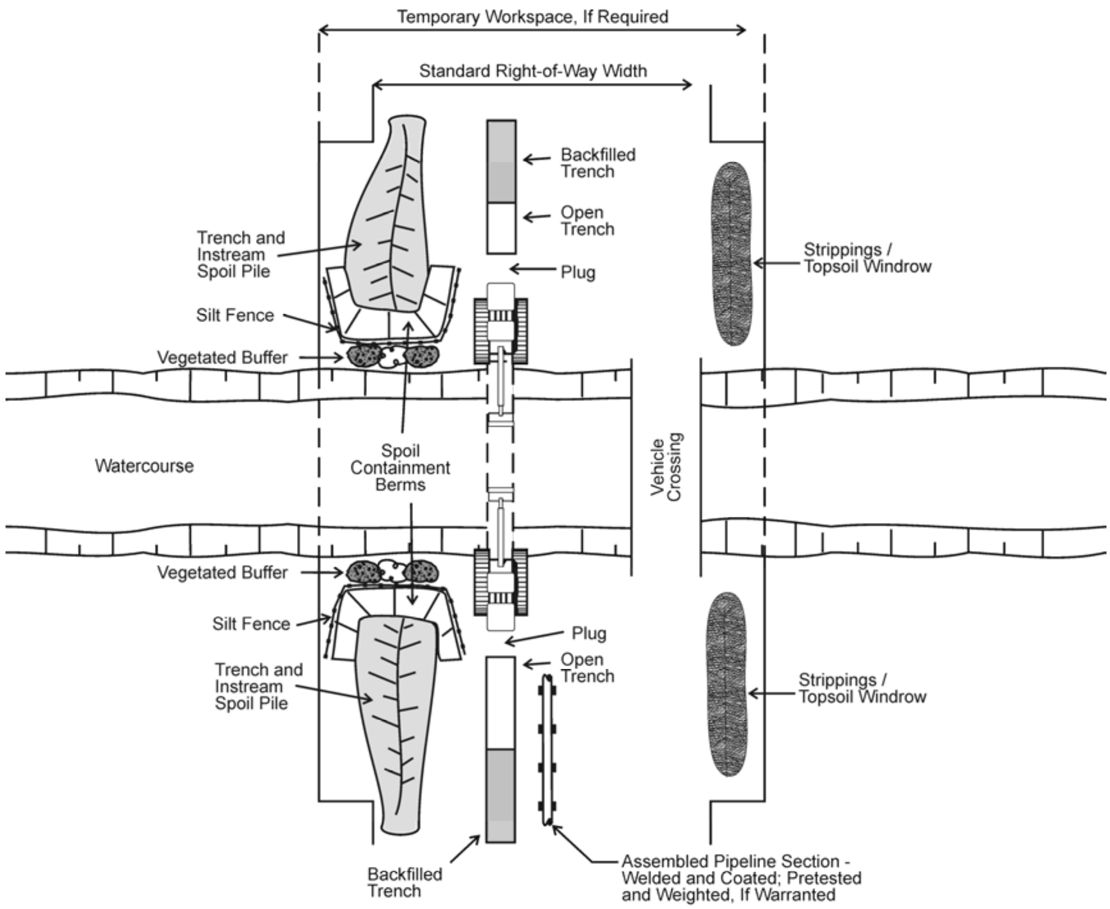

Plan View
(Not to Scale)

Notes:

1. Obtain additional temporary workspace to allow instream spoil to be stored on banks.
2. Install vehicle crossing if warranted.
3. Install sediment and erosion control structures, as required.
4. Leave plugs at end of standard trench.
5. Complete construction of the instream pipe section. Weight and pretest pipe, if warranted, prior to commencement of instream activity.
6. Trench through watercourse retaining hard plugs back from each bank until just prior to pipe installation. Stockpile all instream spoil on banks. Construct berms (*e.g.,* subsoil, saddle weights, shotrock) to prevent saturated spoil from flowing back into watercourse (see Dwg. 16). Maintain streamflow, if present, throughout crossing construction.
7. Lower-in and backfill immediately. Restore stream channel to approximate preconstruction profile and substrate. Attempt to complete all instream activity within 24 hours.
8. If necessary to control water flow and trench sloughing, install temporary soft plugs and dewater trench on to stable vegetated land, not directly to watercourse.
9. Restore, stabilize and reclaim watercourse banks and approaches to as close to original grade as practical.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL OPEN CUT OF SMALL WATERCOURSES

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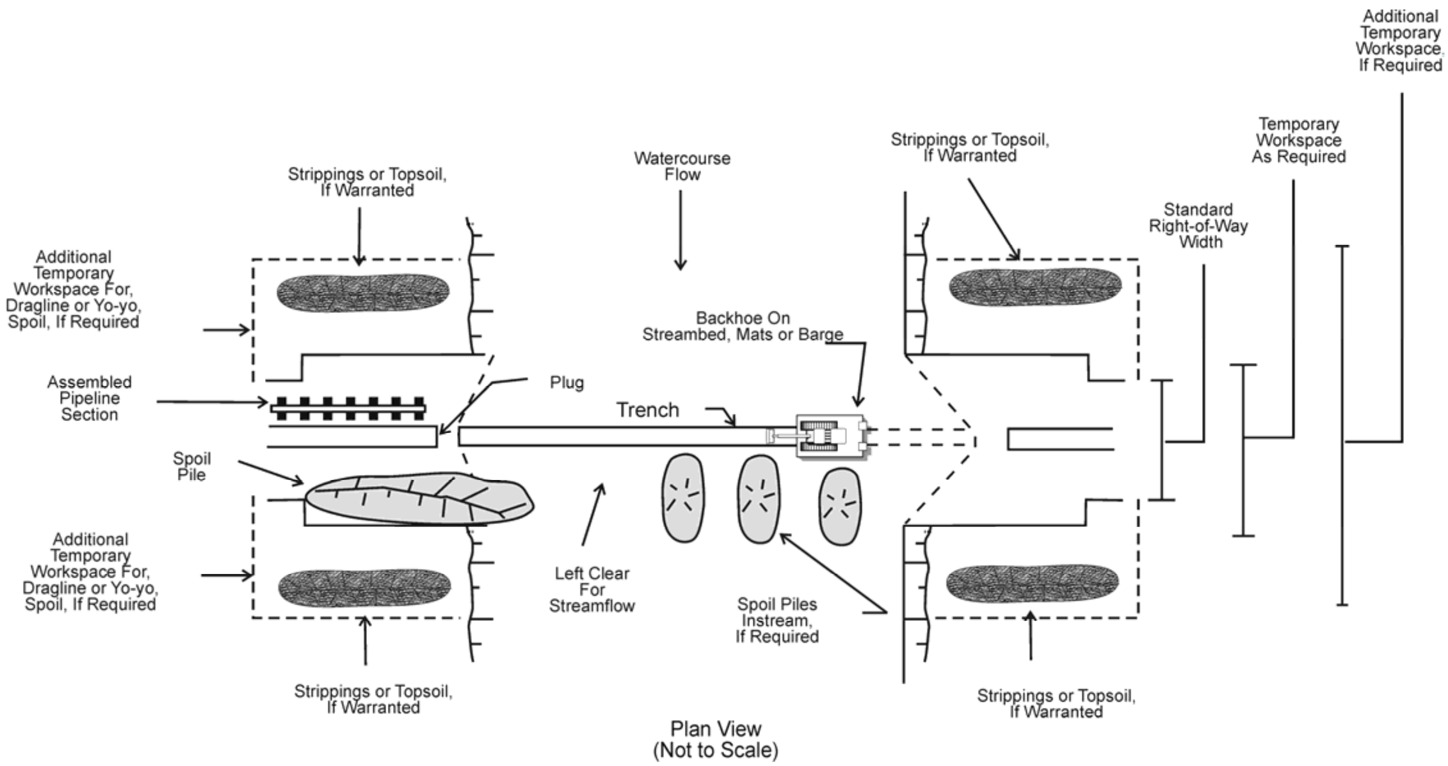
DWG. NO. 2



Notes:

1. Obtain additional temporary workspace to allow as much instream spoil to be stored on the banks as is practical.
2. Leave plugs at the end of the standard trench.
3. Install sediment and erosion control structures, as required.
4. Complete construction of the instream pipe section. Pretest and weight pipe well in advance of anticipated completion of instream trenching.
5. Retain plugs back from each bank until just prior to pipe installation. Stockpile as much spoil on banks as possible. Place instream storage spoil in piles avoiding areas of highest water velocity. Instream spoil should be piled in long piles parallel to flow in order to minimize erosion. Do not windrow spoil across the channel or block more than 2/3 of the channel. Maintain streamflow, if present, throughout crossing construction. Exact trenching and spoil storage requirements will depend on local conditions and equipment used.
5. If necessary, to control water flow and trench sloughing, install temporary soft plugs and dewater trench on to stable vegetated land, not directly to watercourse.
6. Lower-in pipe and backfill immediately. Restore stream channel to approximate preconstruction profile and substrate. Attempt to complete all instream activity as quickly as practical.
7. Restore, stabilize and reclaim watercourse banks and approaches to as close to original grades as practical.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL OPEN CUT OF LARGE WATERCOURSES

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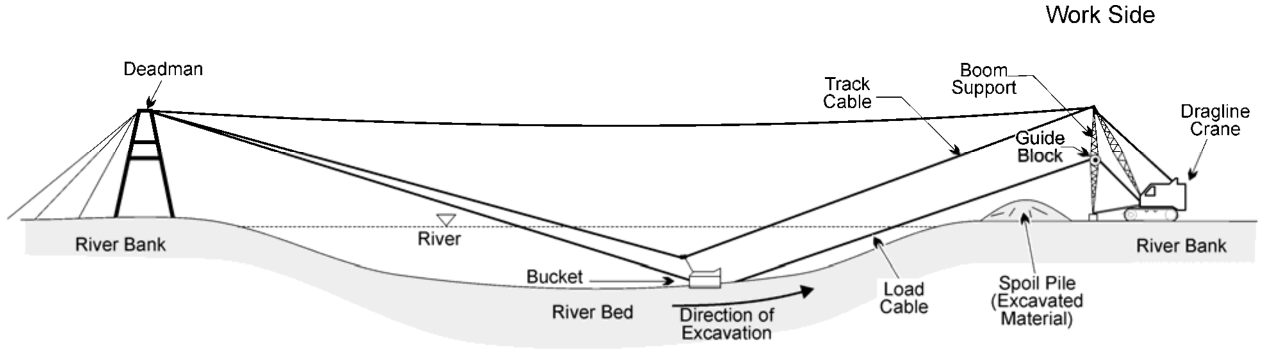
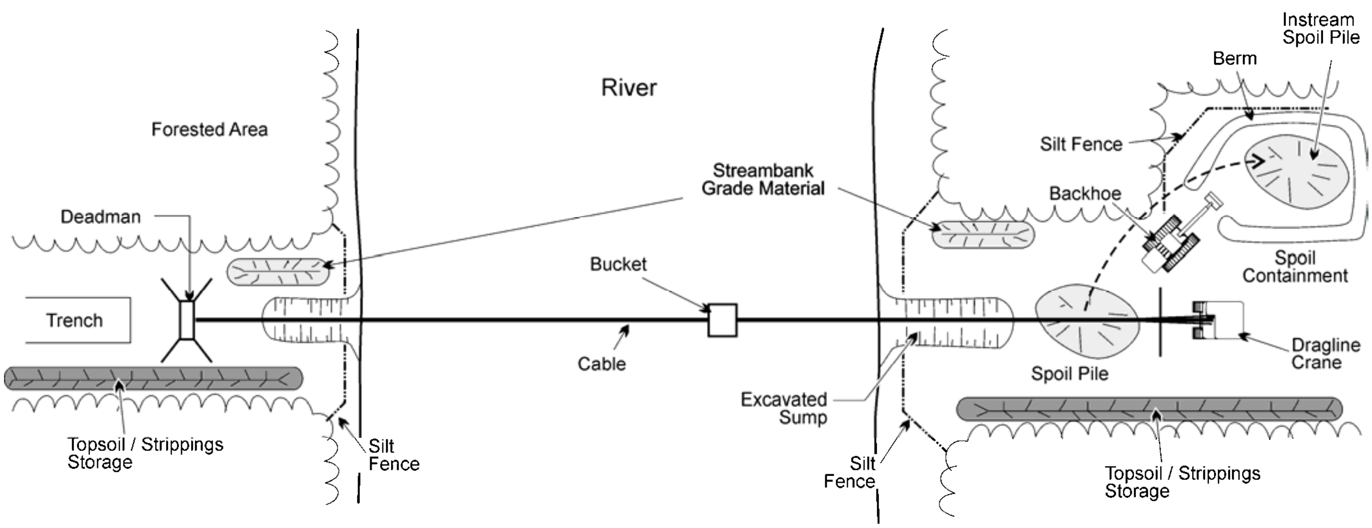
	DWG. NO. 3



Profile
(Not to Scale)



Plan View
(Not to Scale)

Notes:

1. Schedule instream activity for low flow periods and for the appropriate timing window, if feasible.
2. Obtain additional temporary work space to allow instream spoil to be stored on banks.
3. Complete construction of the instream pipe section. Weight and pretest the pipe, if warranted, prior to commencement of instream activity.
4. Construct berm and/or sump to prevent saturated spoil from flowing back into watercourse. Use earth moving equipment to move excavated spoil to a remote storage pile. Attempt to complete all instream activity as quickly as practical.
5. Restore stream channel to approximate preconstruction profile and substrate. Restore, stabilize and reclaim watercourse banks and approaches to as close to original grades as practical.

Source: Adapted from Express Pipeline 1995, TCPL 1994

CONSTRUCTION TECHNIQUE – TYPICAL DRAGLINE

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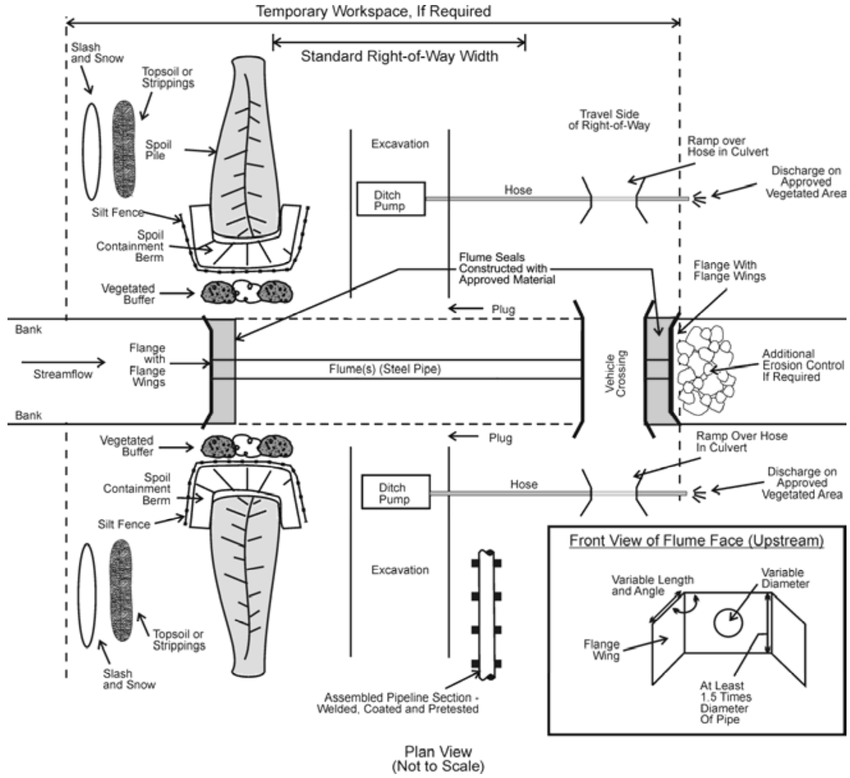
October 2005
DWG. NO. 4



Notes:

1. Install the vehicle crossing, if required, on the work side edge of the right-of-way to allow for a wide excavation.
2. Size flume to handle anticipated flows.
3. Stockpile all required materials prior to beginning instream work. Complete construction of the instream pipe section. Weight and pretest pipe, if warranted, prior to commencing instream activity.
4. Install a pre-assembled flume, or construct a flume and install both an upstream and downstream dam.
5. Install additional erosion control, if required, downstream of the flume outlet.
6. Ensure a tight seal about the dam and flume prior to undertaking trench excavation. Beginning in the early morning, excavate the trench as quickly as practical placing spoil out of the stream channel. Create spoil containment sumps or berms, if warranted, to keep spoil from flowing back into the stream channel.
7. Pump excavation as required to prevent downstream flow of silted water. Direct the pumped water onto vegetated areas well back from the watercourse. Construct water containment sumps, if warranted.
8. Install pipe.
9. Backfill the stream channel first, squeezing the silted water into the bank excavations. Pump or drain the bank excavations while progressively backfilling from the stream channel outward.
10. Complete backfill, leaving a small shallow (< 0.5 m) sump upstream of the downstream dam. Install a pump intake in this sump.
11. Slowly elevate corner of flume (or edge of dam) and/or shut down auxiliary bypass pumps, and allow isolated channel to be flushed with water. Silt-laden water will flow into the shallow sump and then be pumped onto well-vegetated area.
12. Once isolated channel is flushed, remove downstream seal materials.
13. Remove upstream seal materials.
14. Remove the flume.
15. Restore, stablizie and reclaim bed and banks of stream channel to preconstruction profiles.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL FLUME

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	October 2005
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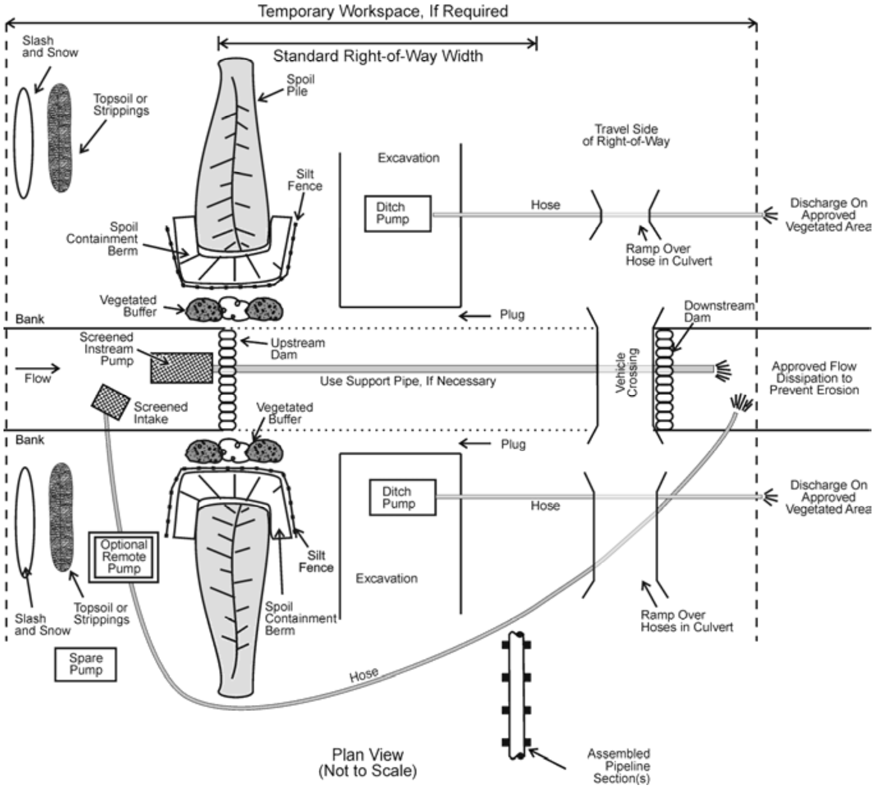

Notes:

1. Install the vehicle crossing, if required, on the work side edge of the right-of-way to allow for a wide excavation.
2. Stockpile all required materials and equipment onsite prior to beginning instream work.
3. Complete construction of the instream pipe section. If warranted, weight, coat and pretest pipe prior to the commencing of instream activity.
4. Begin the operation in the early morning to allow for same day installation, if practical.
5. Install pumps in natural pool upstream of the excavation. Excavate temporary sump within right-of-way if no natural pool exists. Check pump operation to equalize flow.
6. Ensure pumps can handle anticipated flow. Have standby pumps and generators capable of handling 100% of anticipated flow onsite and ready to be used if operating pumps fail.
7. Construct the upstream dam on the edge of the temporary workspace to allow for a wide excavation. Ensure dam is impermeable. Construct dam using sand bags, aquadam, sheet piling or other approved material that ensures a tight seal of the bed and banks.
8. Plug the vehicle crossing culvert or construct the downstream dam. Where a bridge is used, the bridge and dam should be installed as close to the edge of the temporary workspace as practical to allow for a wide excavation.
9. Assess the need to dewater isolated section of the watercourse and ensure tight seal about dams prior to trenching.
10. Excavate trench as rapidly as possible. Create spoil containment sumps, if warranted, to keep spoil from flowing back into the stream channel.
11. Install pipe.
12. Backfill the stream channel first pushing the silted water back into the bank excavations. Pump or drain the bank excavations while progressively backfilling from the stream channel outward. Construct water containment sumps if warranted.
13. Complete backfill, leaving a small, shallow (< 0.5 m) sump just upstream from the downstream dam. Install a pump intake in this sump.
14. Temporarily suspend pump bypass and/or slowly elevate corner of upstream dam and allow isolated channel to be flushed with water. Silt-laden water will flow into the shallow sump and then be pumped onto well-vegetated area.
15. Remove the downstream dam or vehicle crossing plug.
16. Remove the upstream dam or vehicle crossing plug.
17. Restore, stabilize and reclaim bed and banks of stream channel to preconstruction profiles.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL DAM AND PUMP

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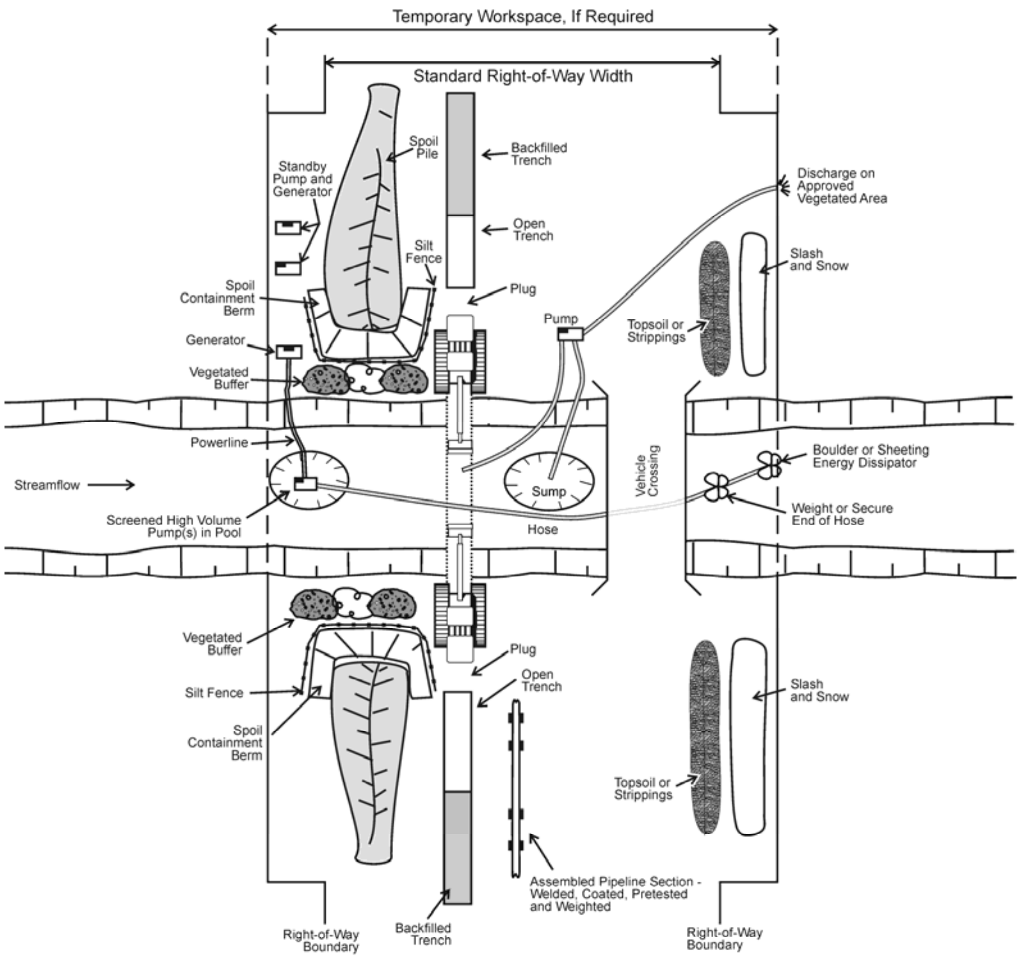

Plan View
(Not to Scale)

<u>Notes</u>:

1. Install vehicle crossing, if required, on the work side edge of the right-of-way to allow for a wide excavation.
2. Ensure adequate electric power supply and adequately sized pumps to handle anticipated flow. Have standby pumps and generators capable of handling 100% of anticipated flow onsite and ready to be used if the operating pumps fail.
3. Install high volume pump in pool located upstream of the excavation. Excavate temporary upstream sump in the right-of-way if no natural pool exits. Add additional pumping capacity if required. Discharge water through or into an energy dissipator into the channel sufficiently downstream of the trench to prevent water flowing back into the excavation.
4. Immediately initiate fish salvage from isolated pools. Ensure fish salvage permit(s) are acquired prior to installing pump.
5. Excavate a small sump downstream of crossing to collect silt laden waters. Install small pumps in sump and trench to discharge silt-laden water on to well vegetated soils away from watercourse.
6. Excavate trench, complete installation and backfill trench. Move hose if warranted to maintain streamflow.
7. Wash backfilled trench area into sump. Pump silt-laden water from trench onto a well vegetated area off right-of-way. Complete this step each evening prior to shutting off upstream pump, if instream work is to occur on successive days.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL HIGH VOLUME PUMP BYPASS

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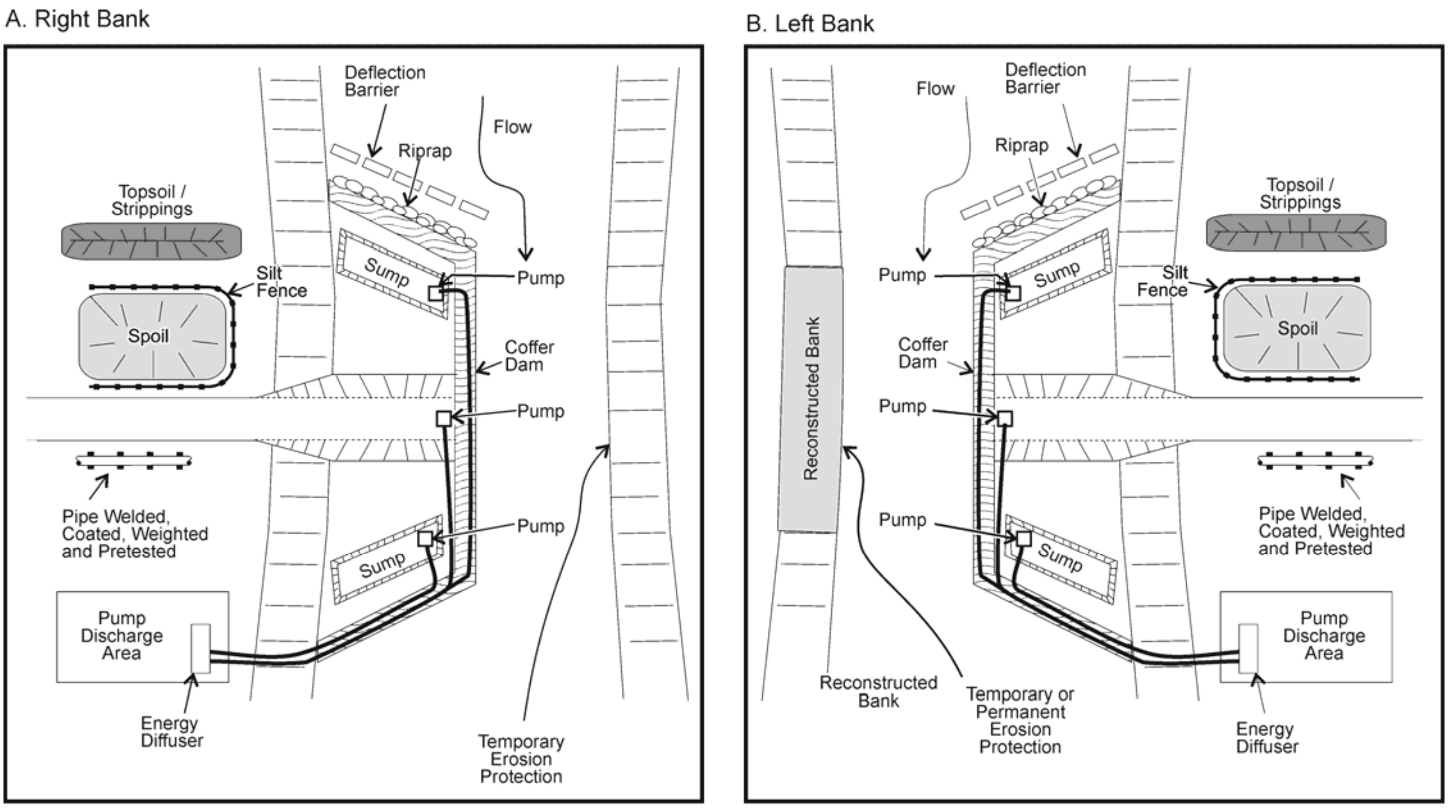
DWG. NO. 7



Plan View
(Not to Scale)

Notes:

1. A crossing-specific drawing to supercede this typical should be prepared for implementation during construction.
2. Ensure sufficient working space within the coffer dam to accommodate a wide unstable ditch.
3. If there is a high velocity streamflow, install deflection barrier (*e.g.,* median barriers) to permit construction of coffer dam outside full streamflow.
4. Construct coffer dam from local materials, sandbags, 1 m^3 sandbags, aquadams, sheet piling, median barriers, gravel or other appropriate material to extend over halfway across the watercourse.
5. Install impermeable barrier within coffer dam.
6. Install riprap on upstream side to protect the dam from erosion if dam is constructed of loose material.
7. Install sumps to collect seepage and then pump to dewatering area.
8. Ensure discharge area can handle the volume of water and silt pumped to shore.
9. Complete trenching, lowering in, backfilling and mark end of pipe.
10. Remove coffer dam, reconstruct bank.
11. Install similar structure on opposite side of watercourse enclosing the marked pipe end.

Source: Adapted from TERA 1996

CONSTRUCTION TECHNIQUE – TYPICAL TWO STAGE COFFER DAMS

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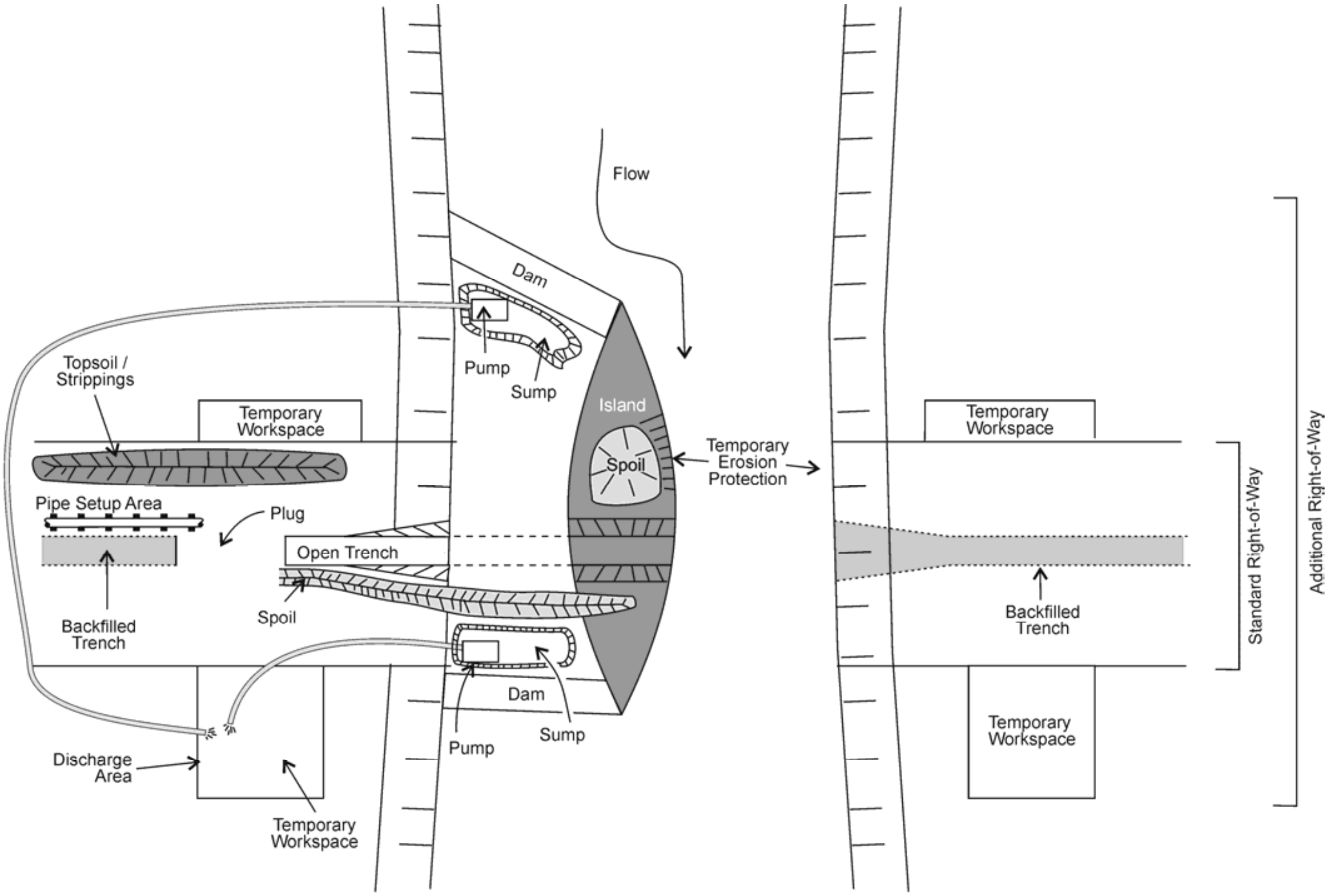
	October 2005
	DWG. NO. 8



Plan View
(Not to Scale)

Notes:

1. If there is a high velocity streamflow, install deflection barrier (*e.g.,* median barriers) to permit construction of dam outside full streamflow.
2. Construct dam from local materials, sandbags, 1 m^3 sandbags, water-filled dams, sheet piling, median barriers, gravel or other appropriate material to extend over halfway across the watercourse.
3. Install impermeable barrier within dam.
4. Install riprap on upstream side to protect the dam from erosion if dam is constructed of loose material.
5. Spoil storage shall be above the high water mark or protected by erosion control measures to ensure that, when the water level rises after all flow has been channelized into one channel, spoil is not washed away.
6. Install sumps to collect seepage and then pump to dewatering area.
7. Ensure discharge area can handle the volume of water and silt pumped to shore.
8. Complete trenching, lowering in and backfilling.
9. Remove dam, reconstruct bank.
10. Repeat process for other channel.
11. Temporary diversion also may be made through abandoned channels as long as steps are taken to minimize a flush of sediment once the watercourse is redirected through the "new" channel.
12. Temporary diversion through a channel excavated into a flood plain is possible if lined or passed through a flexible conduit to prevent excessive erosion along the "new" channel.

Source: Adapted from TERA 1996

CONSTRUCTION TECHNIQUE – TYPICAL CHANNEL DIVERSION

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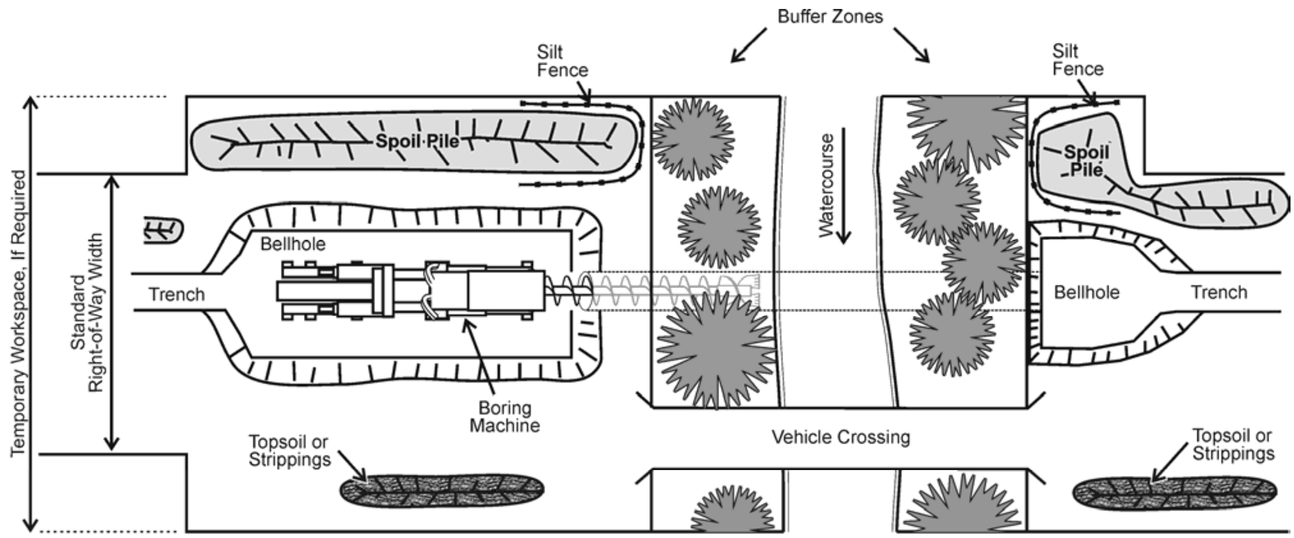
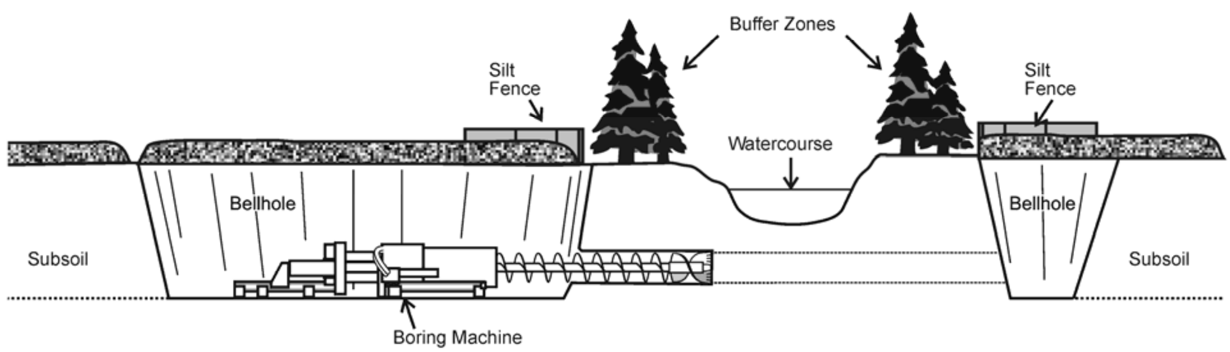


Plan View
(Not to Scale)



Profile
(Not to Scale)

Notes:

1. Acquire and mark additional temporary workspace.
2. Set up equipment back from the edge of the watercourse; do not clear or grade within buffer zone except along the work side, if temporary vehicle crossing is installed.
3. Excavate bellhole. Store spoil on opposite side of right-of-way.
4. Complete boring and tie-in to mainline.
5. Pump bellhole dry if seepage becomes a problem. Dewater bellholes onto stable, vegetated land, not directly back into watercourse.
6. Backfill and compact. Leave a crown to allow for subsidence.

Source: Adapted from TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL BORE OR PUNCH

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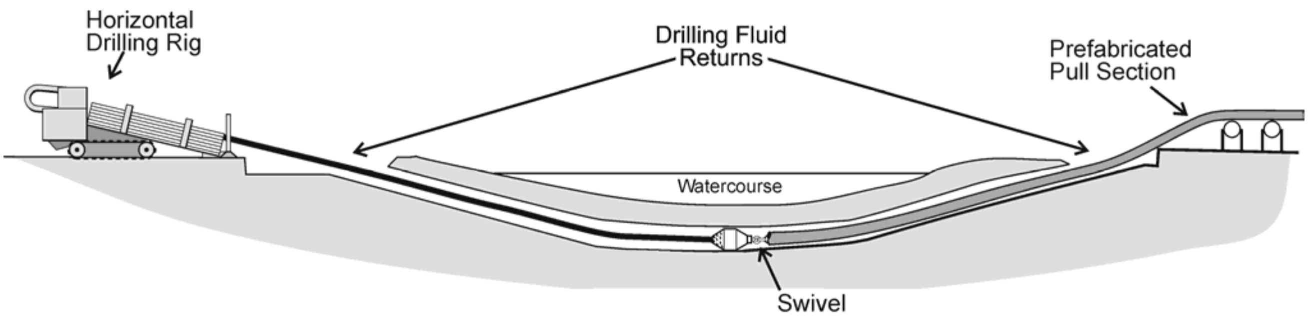
	October 2005
	DWG. NO. 10



Profile
(Not to Scale)

Notes:

1. Obtain geotechnical data prior to initiating drilling. Drilling may not be feasible in some materials such as unconsolidated gravels.
2. Ensure temporary workspace rights have been obtained to conduct monitoring and that access is available for monitoring activities.
3. Set up drilling equipment back from the edge of the watercourse; do not clear or grade within the buffer zone.
4. Employ full time inspectors to observe for an inadvertent mud release into the watercourse.
5. Ensure that only bentonite based drilling mud is used. Do not allow the use of any additives to the drilling mud without the approval of appropriate regulatory authorities.
6. Install suitable drilling mud tanks or sumps to prevent contamination of watercourse.
7. Install sumps downslope from the drill entry and anticipated exit points to contain any release of drilling mud.
8. Dispose of drilling mud in accordance with the appropriate regulatory authority requirements.
9. Prepare a drilling mud release contingency plan.

Source: Adapted from ASCE 1996, TERA 1998

CONSTRUCTION TECHNIQUE – TYPICAL HORIZONTAL DIRECTIONAL DRILL

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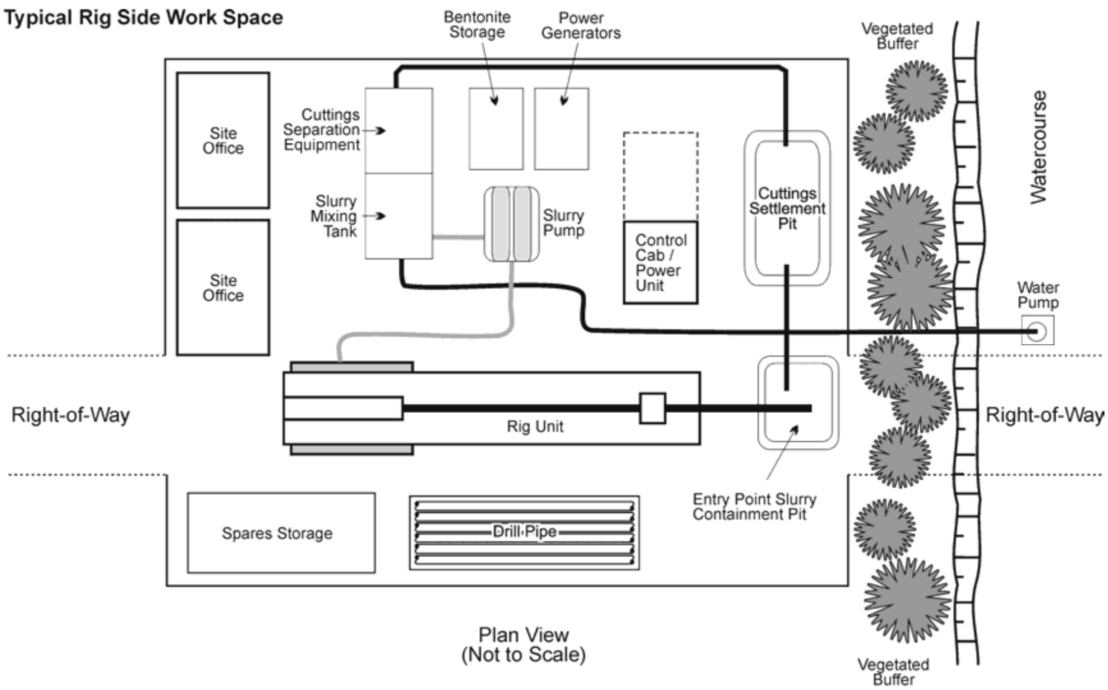
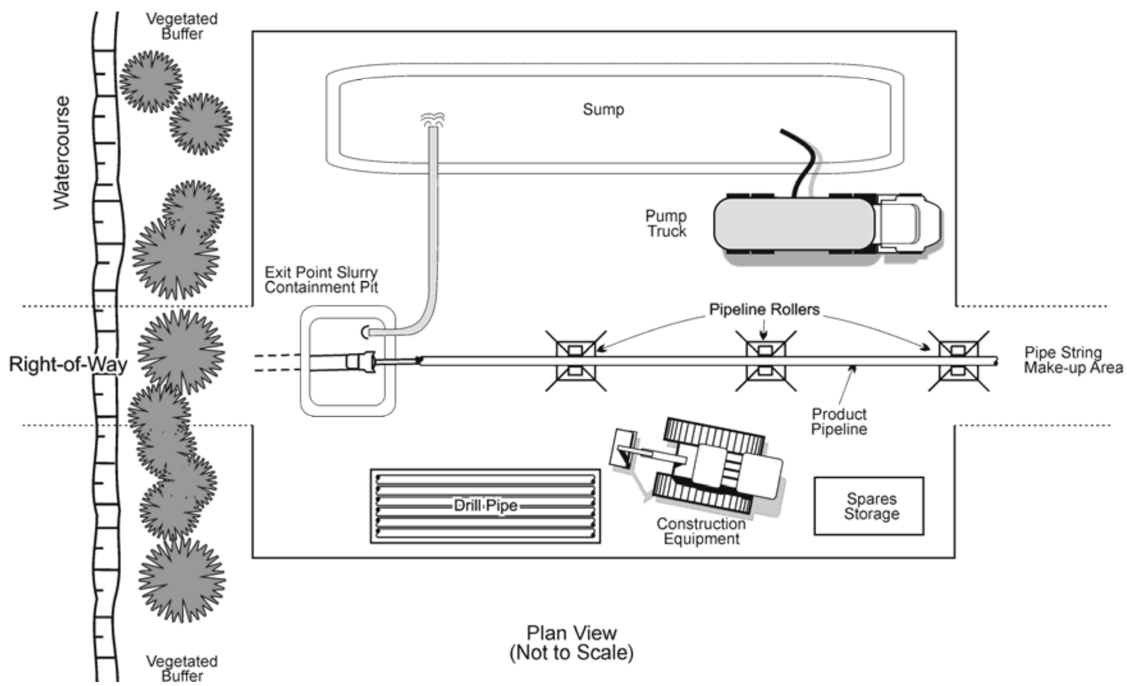
October 2005

DWG. NO. 11 (a)

(A) Typical Rig Side Work Space



(B) Typical Pipe Side Layout



Source: Adapted from ASCE 1996

CONSTRUCTION TECHNIQUE – TYPICAL HORIZONTAL DIRECTIONAL DRILL

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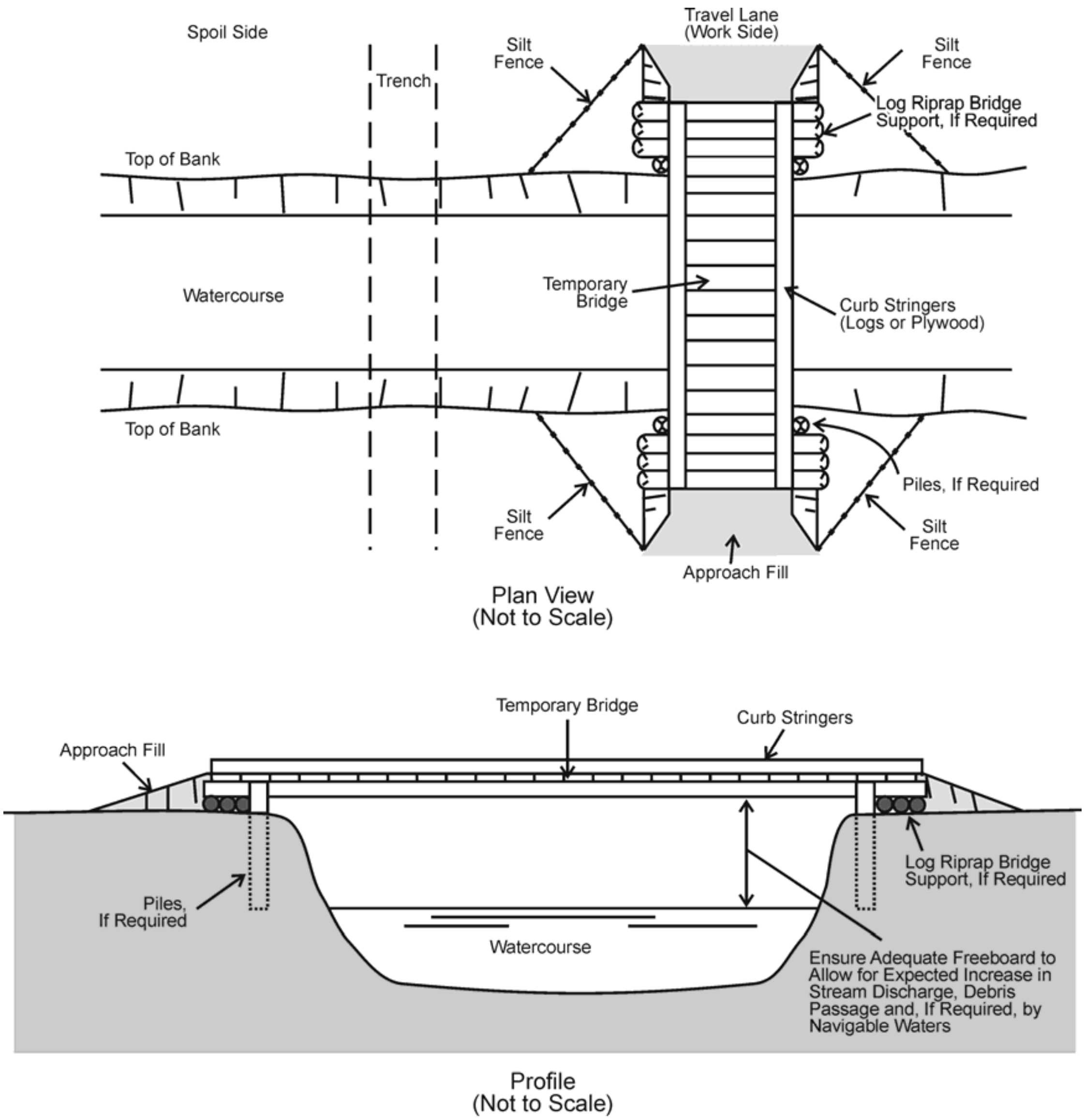
	October 2005
	DWG. NO. 11 (b)



Notes:

1. Install a temporary bridge (e.g., log, pre-fabricated span) to allow vehicles to cross watercourses that are sensitive or that have unstable bed and banks. Bridges are also used where watercourses are too deep, wide or fast to permit an alternative crossing structure. This method minimizes sedimentation of the watercourse, and bank and bed restoration work. It is generally limited to watercourses less than 30 m in width.
2. Utilize approach fills rather than cuts in banks to minimize erosion potential. Do not constrict flow with approach fill or support structures. Ensure adequate free-board to handle anticipated streamflows. Use a geotextile liner to prevent fine material from entering watercourse.
3. Remove bridge immediately after use. If bridge is to remain in place through spring break-up to access final clean-up, it must be designed for spring floods and ice jams. Remove support structures and approach fills. Restore and stabilize banks.
4. Install curb stringers of logs or plywood to ensure that fill material does not spill into the watercourse, where required.

Source: TERA 1998

VEHICLE CROSSING – TYPICAL TEMPORARY BRIDGE

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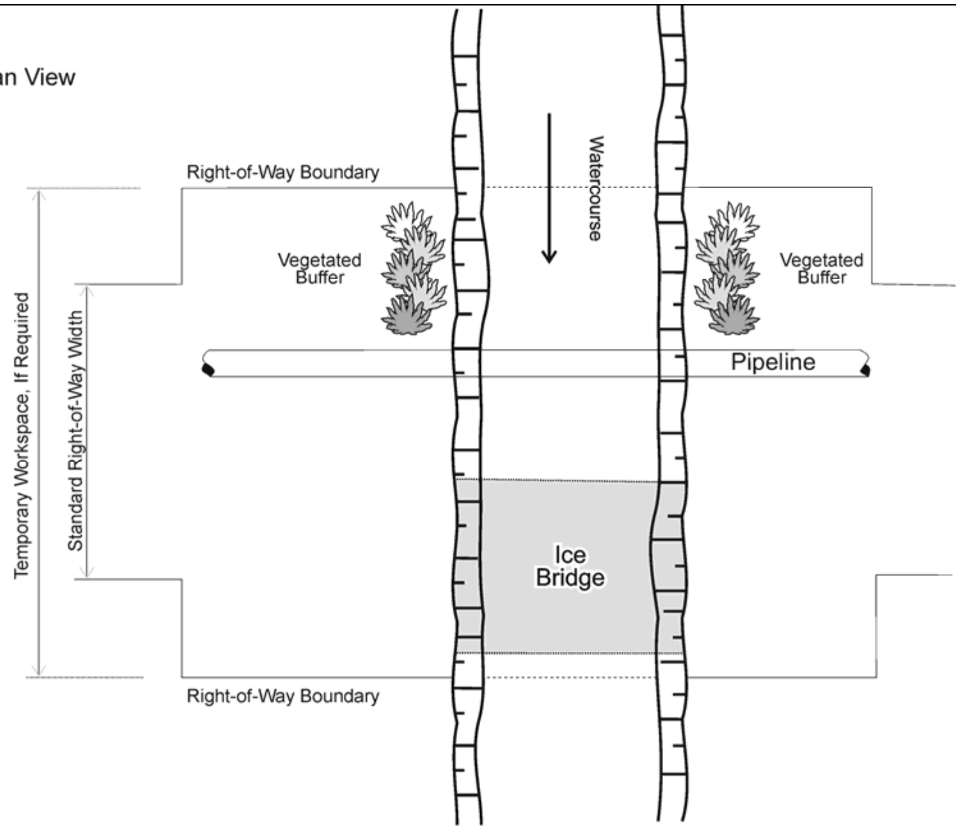
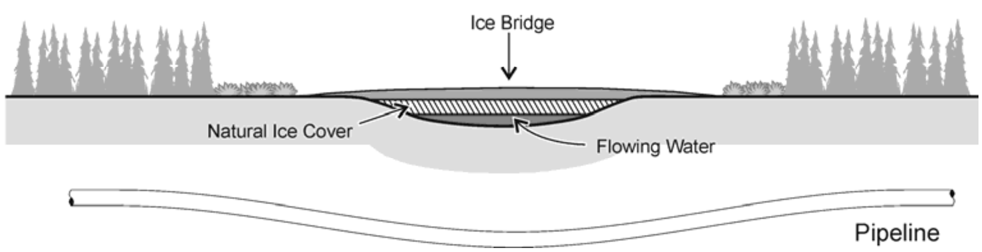
October 2005

DWG. NO. 12

A. Plan View



B. Profile View



Notes:

1. Install ice bridges on winter projects when a safe ice thickness can be maintained.
2. Locate ice bridges at sites with gently sloping banks to minimize cuts in watercourse banks. Use snow and ice to slope approaches, rather than cut banks.
3. Flood ice surface with water and cover with snow to increase load bearing capacity. Logs may be used as a base to strengthen the bridge. The ice bridge should not impede flow.
4. Maintain ice regularly and remove all debris from the ice surface.
5. Remove broken ice from trench area to prevent ice jamming against and under the ice bridge.
6. Remove logs and breach ice bridge by physical means prior to spring break-up.
7. Restore and stabilize banks and approaches prior to spring break-up.

Source: TERA 1998

VEHICLE CROSSING – TYPICAL ICE BRIDGE

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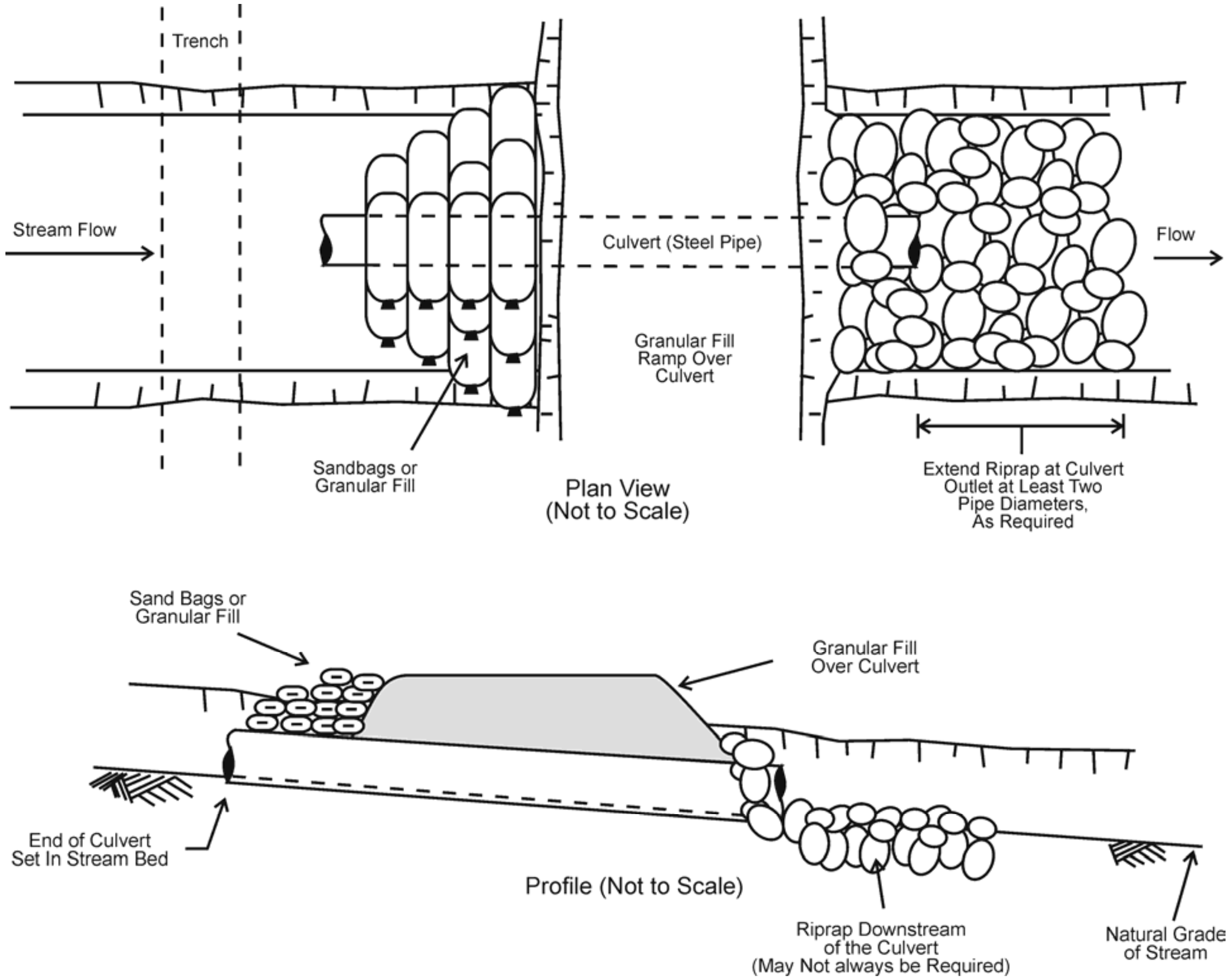
Third Edition	
October 2005	
DWG. NO. 13	

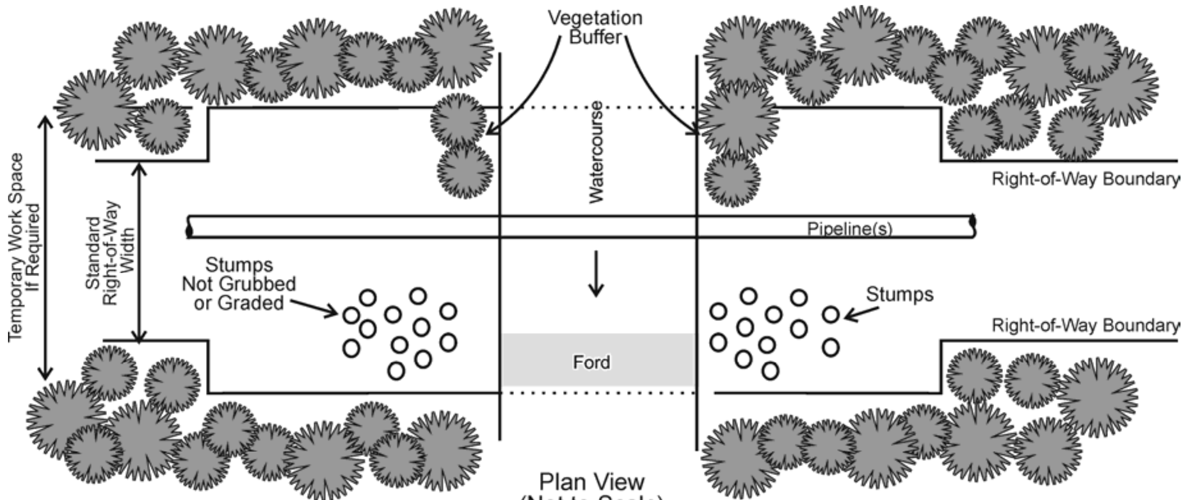


Notes:

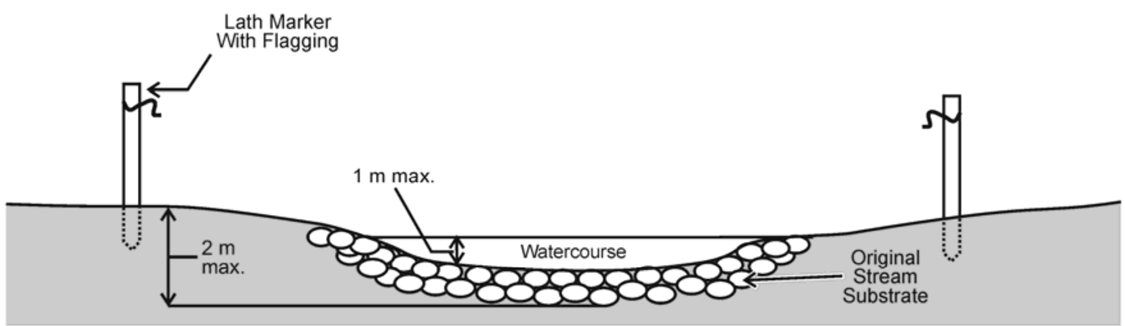
1. Install ramp and culverts to allow vehicles to cross relatively narrow watercourses where sedimentation must be minimized or fish passage allowed.
2. Design culverts to handle 150% of maximum anticipated flows or to a five year flood level and according to specific guidelines where fish passage (i.e., migration) is required. Contact government authorities for minimum water depth specifications, and maximum water velocities. Ensure dam is impermeable.
3. Place ends of culverts below the natural grade of watercourse at an angle that does not exceed normal watercourse gradient. Depth of placement is dependent upon bed type, culvert size and expected flow conditions.
4. Remove temporary culverts and ramp materials when no longer required. Remove culvert and ramp prior to freeze-up (summer construction) and prior to spring break-up (winter construction).
5. Restore and stabilize bed and banks.

Source: Alliance 1998

VEHICLE CROSSING – TYPICAL RAMP AND CULVERT



Plan View
(Not to Scale)



Profile
(Not to Scale)

Notes:

1. Use fords to provide vehicular access across relatively shallow (less than 1 m) and narrow watercourses with granular beds and stable banks. Where water depth, streambed composition or banks slopes could pose trafficability problems for rubber tired vehicles, limit ford traffic to tracked equipment.
2. Do not use ford during fish spawning, incubation or migration periods.
3. Minimize grading in proximity to watercourse. Grade and grub only along the trenchline and an area immediately adjacent to the trenchline. Pull soil and debris away from watercourse, if banks require sloping.
4. Minimize use of ford.
5. Stabilize banks and approaches with granular blanket underlain by a geotextile, if warranted.
6. Mark boundaries of ford on both sides of crossing to confine all vehicle traffic to ford.
7. Restore and stabilize beds and banks to original contour when ford is no longer needed. Granular blanket need not be removed if it is not a barrier to fish during low flow conditions.

Source: TERA 1998

VEHICLE CROSSING – TYPICAL FORD

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	October 2005
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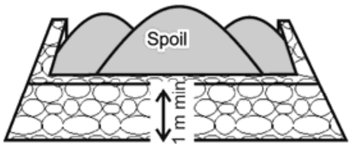
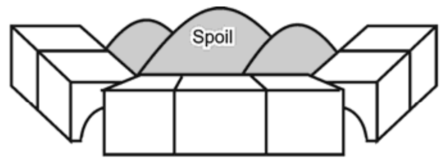
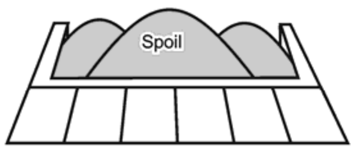


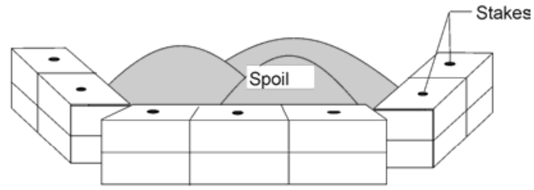
1. Windrow Boulders and Shot Rock



2. Saddle Weights



3. Subsoil Berm



4. Straw Bales (staked)

Not to Scale

Notes:

1. Construct sump or berms to contain excavated instream spoil so that silty runoff does not enter watercourse or flow off right-of-way.

2. Strip topsoil from area to be used as spoil storage.

3. Maintain sufficient buffer from the top of the streambank.

4. Berms which do not adequately prevent leakage, such as those made of boulders, shotrock or saddle weights may need a geotextile liner to prevent silty water from entering watercourse.

Source: Adapted from Alliance 1998

SEDIMENT CONTROL – TYPICAL SPOIL BERMS

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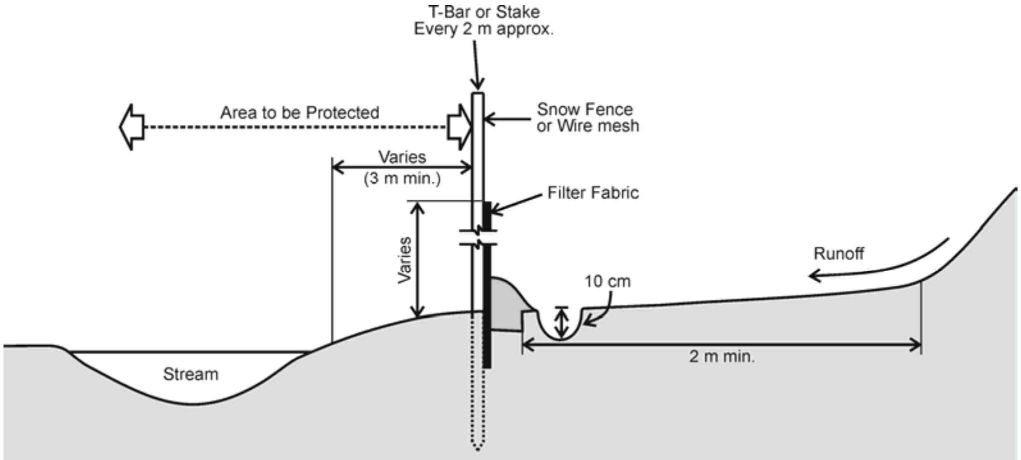
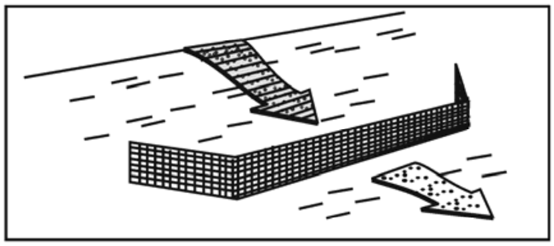
	October 2005
	DWG. NO. 16



Side View of Silt Fence
(Not to Scale)



Oblique View
(Not to Scale)

Notes:

1. Watercourses that have moderate to high sensitivity of fish habitat and/or have steep approach slopes at the proposed crossings may need silt fences during construction, as determined by the Environmental Inspector.
2. Install silt fences at the base of approach slopes following clearing and grading using the method and materials above or other approved designs.
3. Ensure silt fence is keyed into the substrate. Excavate a narrow trench, place the base of the silt fence in the trench and place the fill back into the trench, securing the silt fence in place.
4. Place silt fences a minimum 2 m, if feasible, from the toe of the slope in order to increase ponding volume.
5. Maintain silt fences throughout construction.
6. Ensure that silt fences, if removed or damaged, are reinstalled or repaired prior to the end of the work day.
7. Maintain silt fences in place at the base of the approach slopes until revegetation of the right-of-way is complete.
8. In areas with frequent traffic, install two or more silt fences in a staggered and overlapped configuration to allow vehicle passage without removal or opening of the silt fence.

Source: Adapted from TERA 1998, Alliance 1997

SEDIMENT CONTROL – TYPICAL SILT FENCES

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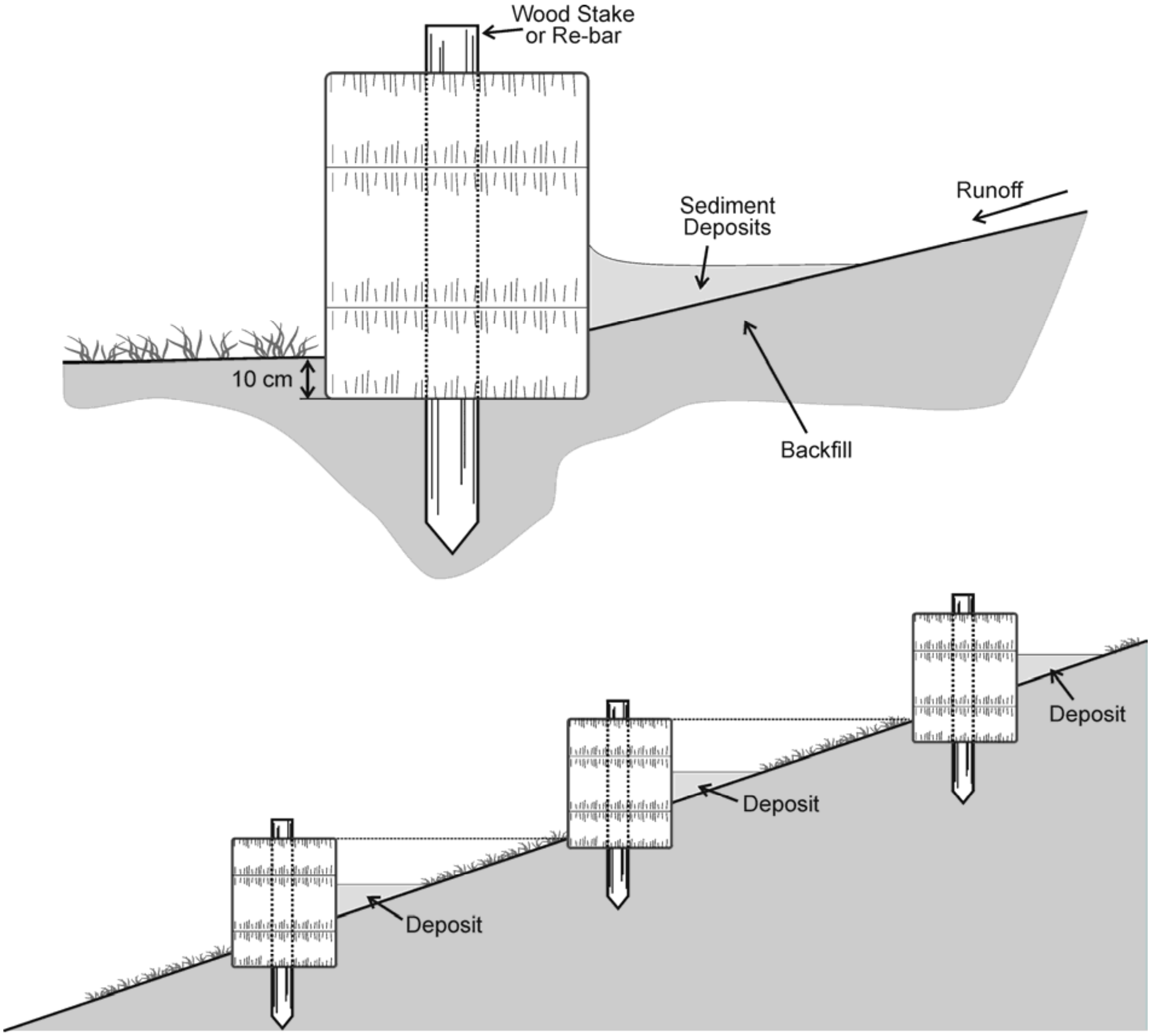
October 2005

DWG. NO. 17



Profile
(Not to Scale)

Notes:

1. Construct straw bale filters to contain excavated instream spoil so that silty run off does not enter watercourse or flow off right-of-way.
2. Use straw bale filters on long unprotected slopes to prevent surface erosion from entering watercourse.
3. Where several lines of bales are installed on a slope in a more permanent application, erosion will be minimized if the top of the downslope bale is on the same level as the bottom of the next line up.

Source: TERA 1998

SEDIMENT CONTROL – TYPICAL STRAW BALES

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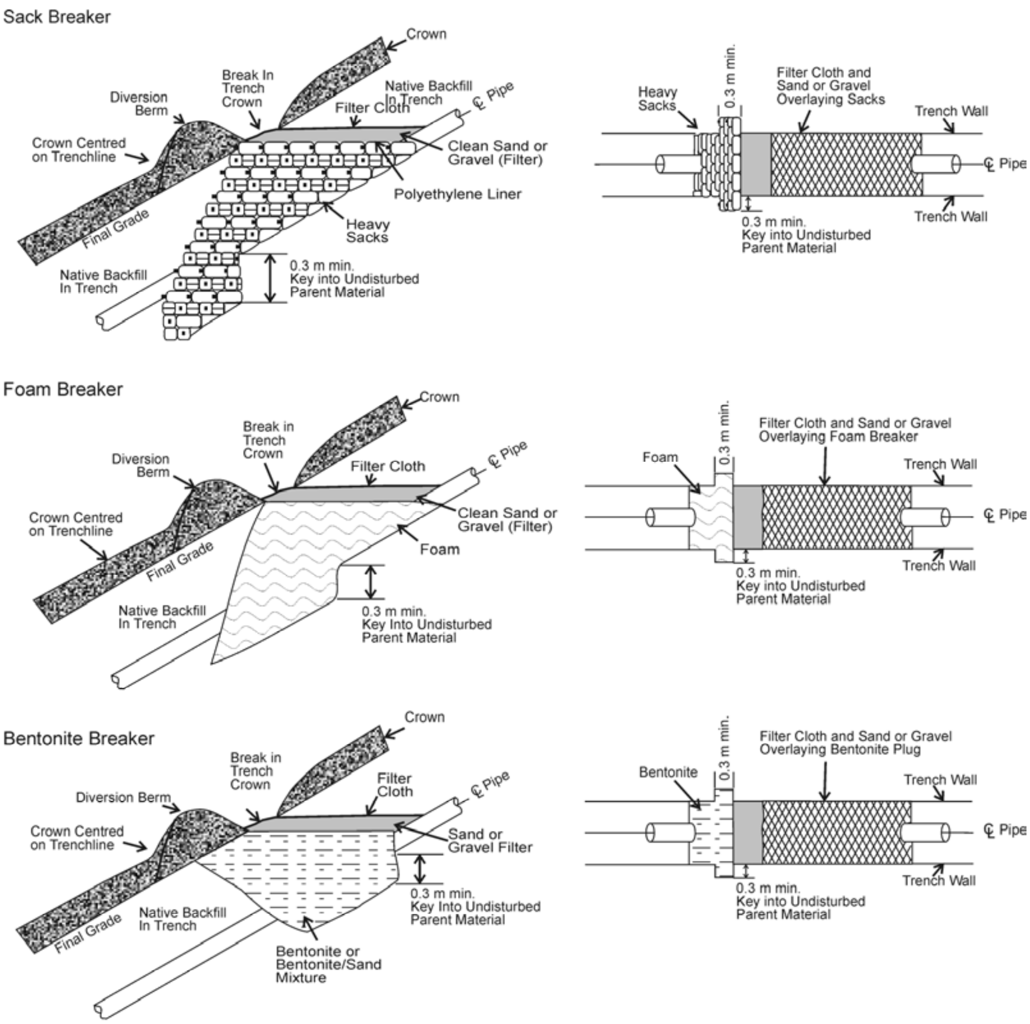
	DWG. NO. 18



Profile
(Not to Scale)

Plan View
(Not to Scale)

Notes:

1. Install trench breakers to control water seepage along the trench line and prevent erosion of backfill materials.
2. Trench breakers may be constructed using earth filled sacks, bentonite, foam or equivalent materials to provide a barrier to water seepage.
3. The drawings above provide a schematic representation of trench breaker installation. Final locations and design of trench breakers will be determined by the project engineer based on site specific conditions at the time of construction.
4. Dig keys into trench bottom and sides to the extent feasible for added stability.
5. Install a prefabricated drain or a layer of sand or gravel covered with filter cloth over the breaker.
6. Backfill native material and mark location of breaker.
7. Ensure cross ditches are located over the end of the drain.
8. Construct diversion berms downslope from the breaker but not over the end of the drain.
9. Ensure that trench crown does not encroach upon the breaker drain or cross ditch.
10. Backfill trench on downslope side of breaker before upslope side.

Source: Adapted from Alliance 1997

SUBSURFACE DRAINAGE CONTROL – TYPICAL TRENCH BREAKERS

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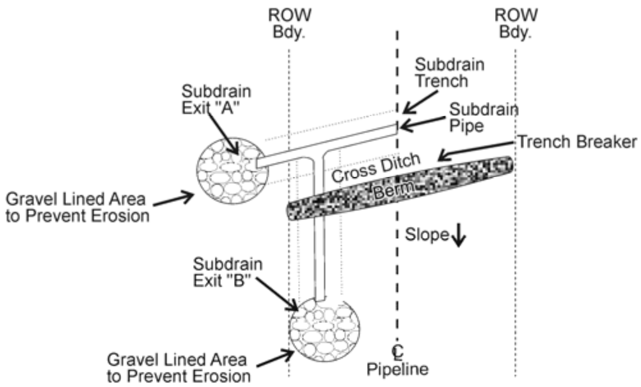
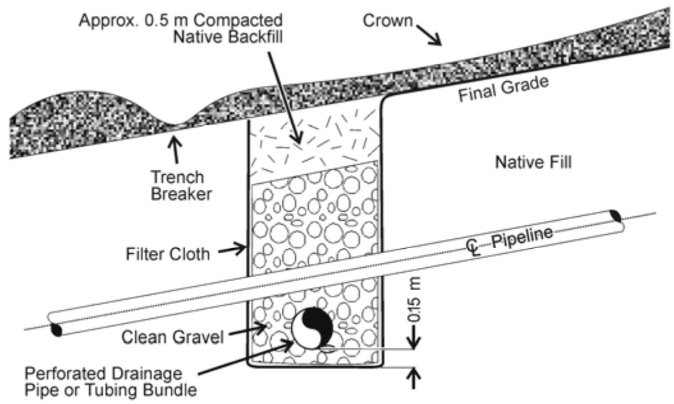
DWG. NO. 19



Plan View
(Not to Scale)



Profile
(Not to Scale)

Notes:

1. Install a subdrain to divert shallow groundwater flow away from the pipeline, to improve slope stability. Clean gravel and a filter cloth ditch liner, permits drainage aiding in retention of backfill. In certain circumstances, a parallel drain may be installed lengthwise down the slope underneath the pipeline. A geotechnical engineer can advise as to which method is most appropriate.
2. Install trench breaker downslope of drain, where drains cross pipeline trench, to prevent drain water flowing down pipe trench.
3. Determine the location of drain by on-site investigation considering such factors as groundwater conditions in trench, soil types, local topography, and drainage patterns. Discharge may either be off right-of-way on the downslope side of the subdrain (see Subdrain Exit "A"), or on right-of-way downslope of the berm (see Subdrain Exit "B"). Special permission will be required from the appropriate regulatory authority and landowner to construct a subdrain exit off right-of-way. Ensure discharge is into a well protected area with gravel, riprap or vegetation.
4. Skew cross drain 5^{o} off horizontal to ensure sufficient drainage.
5. The above drawing is a schematic diagram. A geotechnical engineer should be consulted for the detailed site specific drain design and the incorporation of the trench breaker.

Source: Adapted from Alliance 1997

SUBSURFACE DRAINAGE CONTROL – TYPICAL SUBDRAIN

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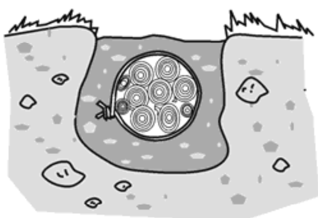
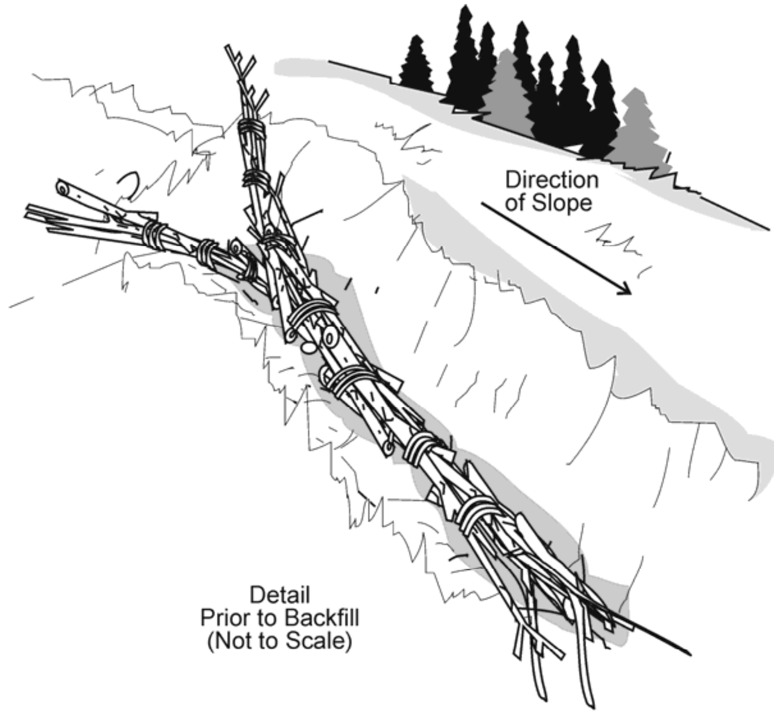
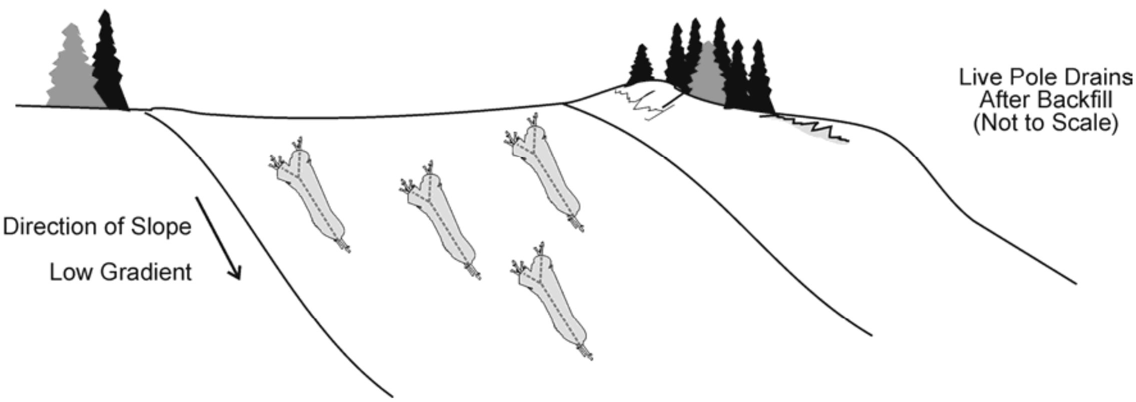
DWG. NO. 20



Profile
(Not to Scale)



Detail
Prior to Backfill
(Not to Scale)



Notes:

1. Excavate a shallow trench parallel with the slope and within regions of excessive moisture.
2. Construct a bundle of willow cuttings, alternating tips and butts, by tying with twine as tightly as practical. Twigs and branches should not be trimmed unless inhibiting the tightness of the bundle.
3. Backfill over the bundle except for bundle ends. Tamp to compact the soil. The bundles may be anchored or staked on erosion prone slopes.

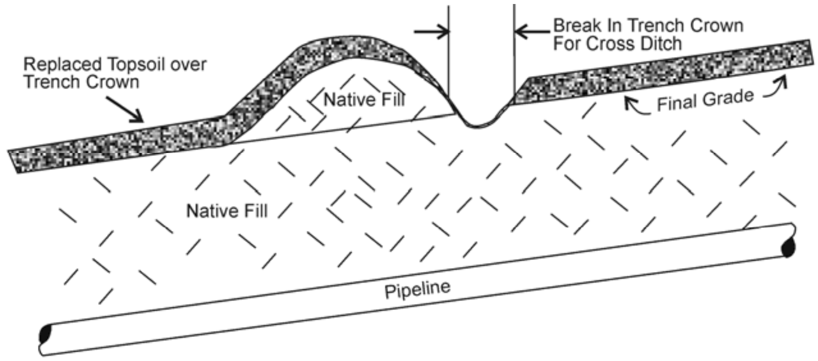
Source: Adapted from CAPP Third Edition (TERA 2005)

SUBSURFACE DRAINAGE CONTROL – TYPICAL POLE DRAINS

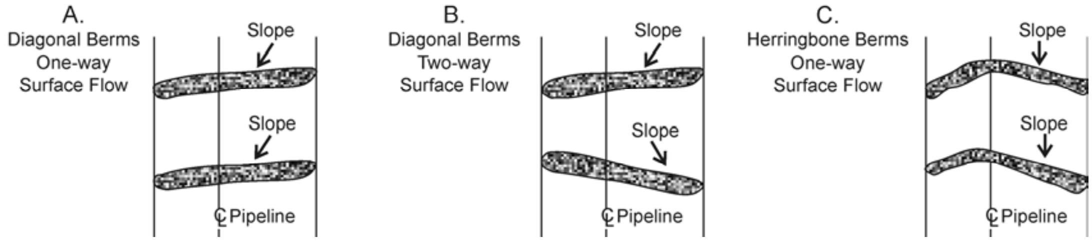
CAPP • CEPA • CGA

	Third Edition
	October 2005
	DWG. NO. 21

Profile
(Not to Scale)



Plan View
(Not to Scale)



Notes:

1. Install diversion berm and cross ditch in conjunction with final clean-up and reclamation on moderate and steep slopes to divert surface water off the right-of-way. Also install berms immediately downslope of trench breakers to collect seepage forced to the surface.
2. Construct diversion berm of compacted native soils where extensive disturbance of the sod layer has occurred. Diversion berms should be constructed of timbers, imported logs, wattles (interwoven twigs and branches), straw bales or sandbags if disturbance of the sod layer is limited. Avoid use of organic material. Where native material is highly erodible, protect upslope of berm and base of cross ditch with sod or by burying a geotextile liner 16 to 20 cm below the surface or armour upslope face of berm with earth filled sand bags.
3. Typical diversion berm height is approximately 30 to 75 cm. Inspect berms after heavy rains and the first spring following construction; replace or restore berms if warranted.
4. Leave a break in trench crown immediately upslope of diagonal berm and cross ditch to allow passage of water across right-of-way.
5. Use diagonal berms where direction of slope and surface water movement is oblique to pipeline right-of-way.
6. Use herringbone berm and cross ditch where direction of slope and surface water movement is parallel to right-of-way so runoff does not cross ditch line.
7. Determine location and direction of berm based on local topography and drainage patterns. Skew berms with downhill gradient of 5-10%.
8. Typical diversion berm spacing

Slope Gradient (%)	Typical Spacing (m) *
<8; <15	as required
8-14; 15-25	45
14-17; 25-30	34
17-20; 30-35	20
>20; >35	10-15

* Rely on field judgment to determine appropriate spacing. For example - install berms approximately 50% closer than indicated on highly erodible materials such as glacial-lacustrine deposits.

9. To facilitate traffic on the right-of-way during temporary applications, straw bales may be inserted in the berm as a "gate". The bales may be removed for access, but replaced each night.

Source: Adapted from Alliance 1997

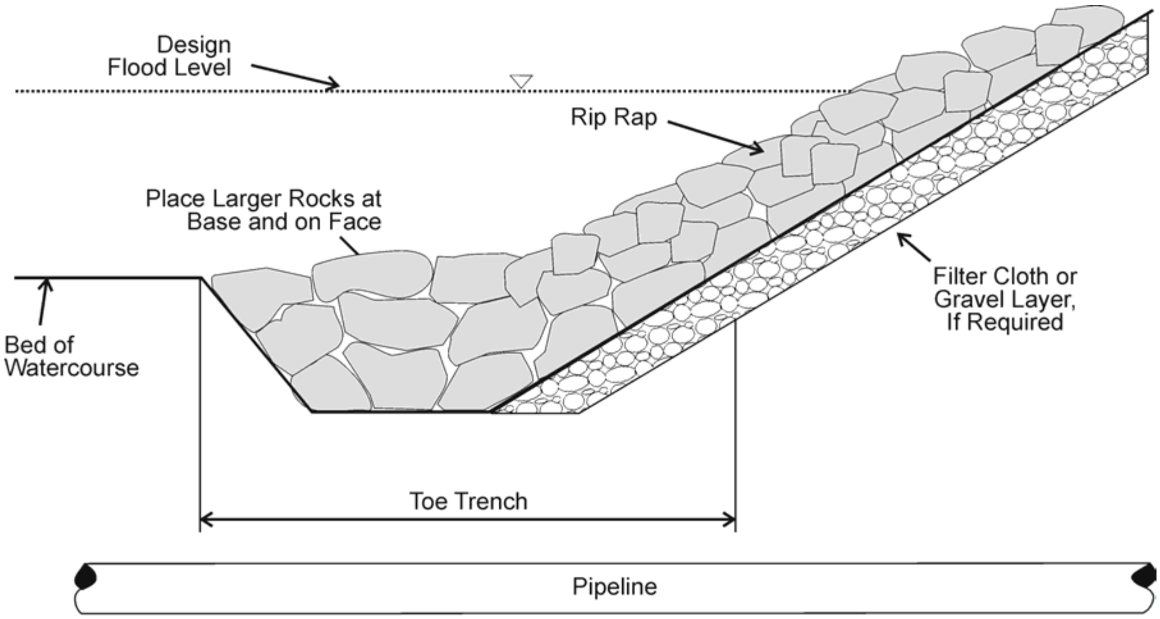
SURFACE EROSION CONTROL – TYPICAL CROSS DITCHES AND DIVERSION BERMS

CAPP • CEPA • CGA

Third Edition

October 2005

DWG. NO. 22



Profile
(Not to Scale)

Notes:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Remove all stumps, organic matter and work material and grade/prepare banks to a maximum slope as directed by a geotechnical engineer.
3. Construct toe trench to key in bottom of armour protection, or adopt thickened toe option.
4. Install filter cloth (geotextile) or gravel filter layer.
5. Place rip rap on slope to be protected such that a well-interlocked, smooth layer is produced.
6. Rip rap should be dense, durable, roughly equidimensional (not flat and thin), angular and clean.
7. Size of rip rap used is dependent upon slope of bank and water velocity.
8. The minimum thickness of a rip rap layer shall be 1.5 to 2 times the approximate dimensions of rock being used.
9. Key in up and downstream ends of the armoured bank in a manner such that it will not be outflanked.
10. Rip rap should extend 0.5 m (min) above design flood level. If design flood level is above the top of the bank, rip rap should be placed to the top of the bank.
11. Rip rap should be flush with bank adjacent to the right-of-way.

Source: Alliance 1998

STREAMBANK PROTECTION – RIP RAP ARMOUR

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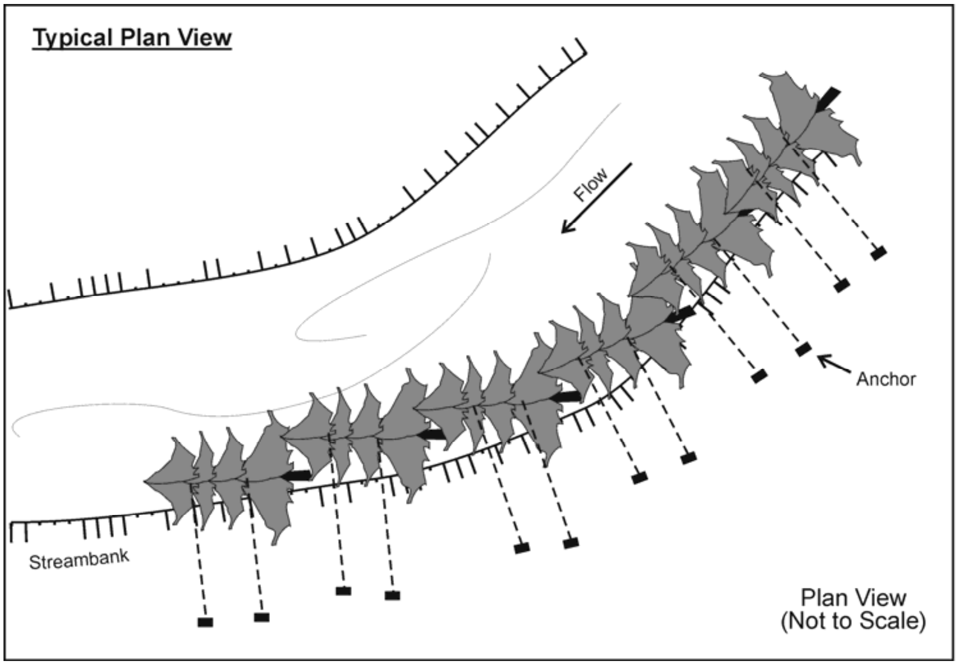
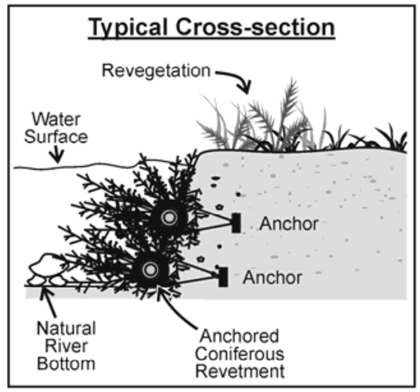
Third Edition

October 2005

DWG. NO. 23





Notes:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Select only good, sound, straight coniferous trees with adequate branches and a minimum length of 10 m.
3. Do not trim any branches and handle with care. Leave root ball intact if possible and transport the trees to the site with a minimum of handling to reduce damage to the branches. To the extent practical, remove soil material from the rootball before placing the tree instream. Place the trees lengthwise along or across the eroding bank to be protected beginning at the downstream end with the tips of the trees pointed in the downstream direction.
4. Begin assembly of the tree revetment at the downstream end and place tie back cable on the tree butt (largest end). Attach the cable to a suitable deadman or large armour rock with a drilled hole. Bury the anchor securely in the adjacent bank.
5. Place the butt of the next tree one-half the length of the previous tree or less upstream along the bank, so there is an overlap of the trees. If possible, cable the trees together in addition to cabling to an anchor buried in the bank.
6. Rock armour may be added along the toe of the slope, beneath the trees to reinforce the level of protection provided.
7. Maintenance, consisting of replacing severely damaged trees, will extend the life span.
8. Coniferous tree revetments also may be used as instream cover.

Source: Alaska Department of Fish and Game (n.d.)

STREAMBANK PROTECTION – TYPICAL CONIFEROUS TREE REVETMENT

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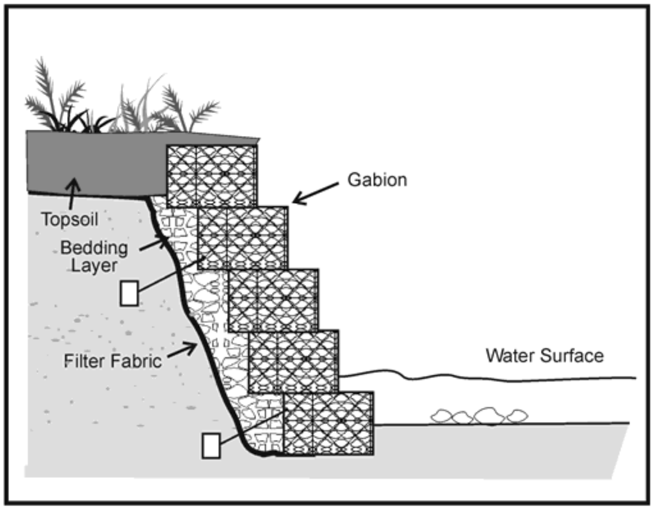
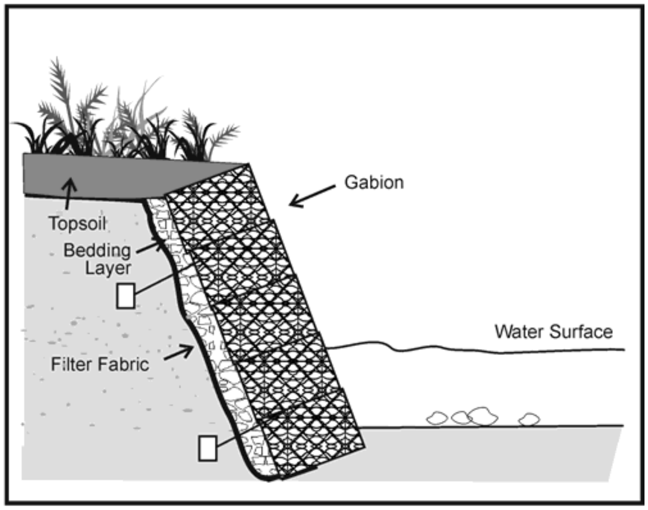
	Third Edition
	October 2005
	DWG. NO. 24

(A) Gabions Offset to Maintain Bank Slope



(B) Gabions Installed Flat Against Streambank



Profile
(Not to Scale)

Notes:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Gabions can be installed on slopes that exceed 1.5:1. Installation flat to slope is preferred on high banks.
3. Gabions should be installed to a height of about 1 m above high water level.
4. Care should be taken not to restrict stream channel capacity, particularly on smaller watercourses.
5. A key trench is to be excavated along the toe of the bank to a point below anticipated scour depth. Place filter fabric and a bedding layer of coarse gravel on excavated slope as gabions are installed.
6. Gabions should be tied together with heavy gauge wire and anchored into the banks at the up and downstream ends.
7. Fill gabion baskets in layers with angular rock larger than the mesh openings. Close and tie down the first row and repeat. Backfill behind baskets and cap with topsoil.

Source: Adapted from Envirowest 1990

STREAMBANK PROTECTION – TYPICAL GABION BASKETS

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	Third Edition
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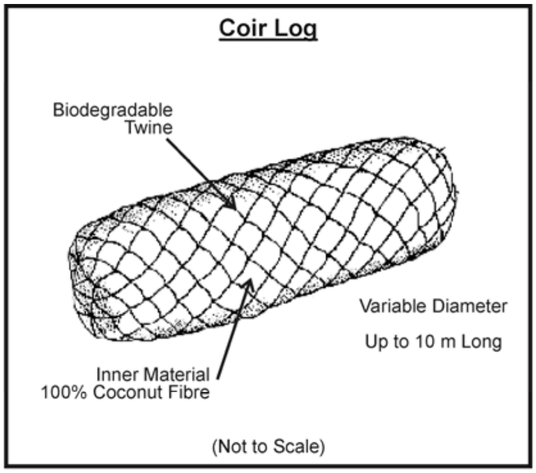

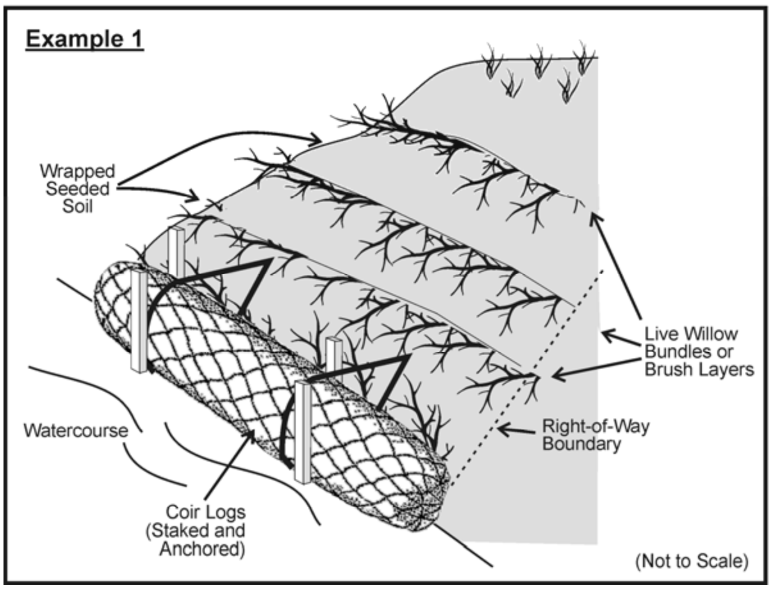

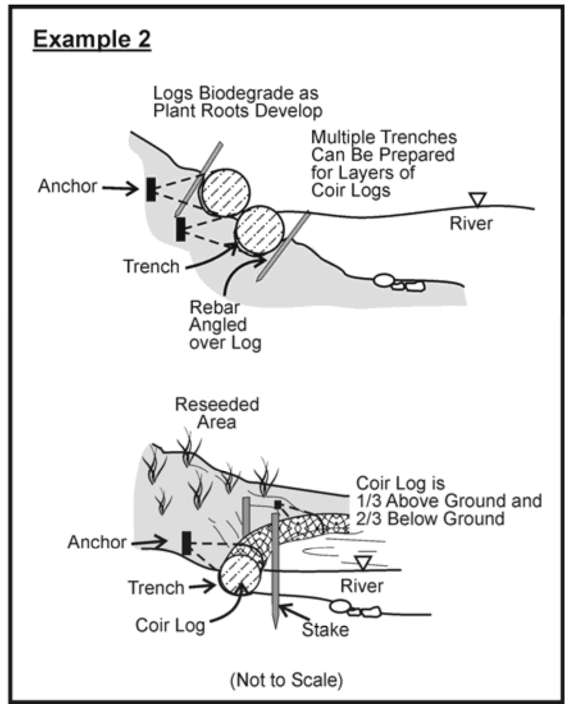

Notes:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Install partially buried coir logs across entire width of disturbance. Anchor logs securely to prevent damage from ice and/or streamflow. Wooden/live stakes, curved rebar or earth anchors may be used. Additional cable anchors may be warranted.
3. Store, move and install when dry.
4. Coir logs may be seeded or cuttings may be inserted.

Source: Adapted from Alaska Department of Fish and Game 1997

STREAMBANK PROTECTION – TYPICAL COIR LOGS

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	October 2005
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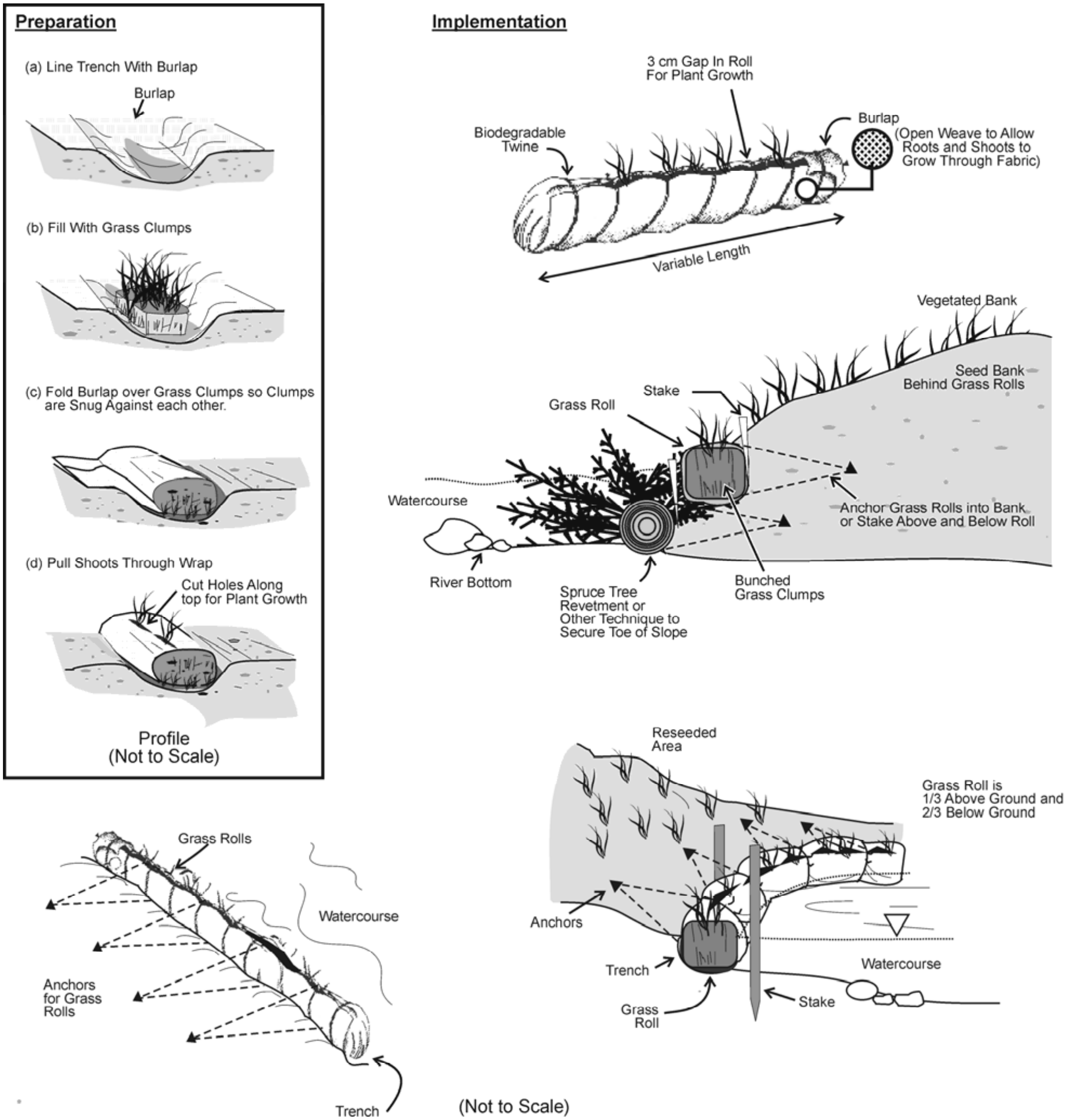

Notes:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Excavate a shallow trench along the high water mark parallel to the toe of the bank and line with burlap.
3. Install sod in the middle of the roll and wrap with burlap covers. Tie with twine and cut slits to expose sections of sod.
4. Stake or anchor firmly ensuring up and downstream ends are secured to prevent washing out.

Source: Adapted from Alaska Department of Fish and Game 1997

STREAMBANK PROTECTION – TYPICAL GRASS ROLL

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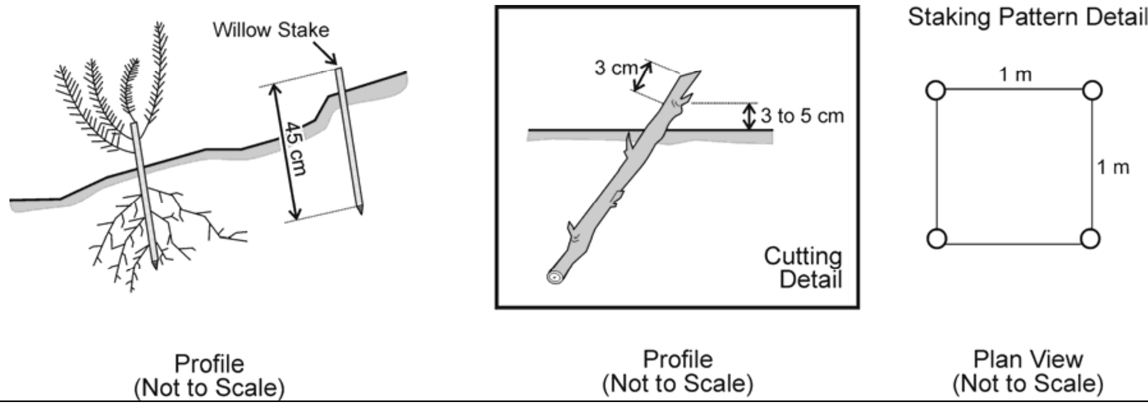
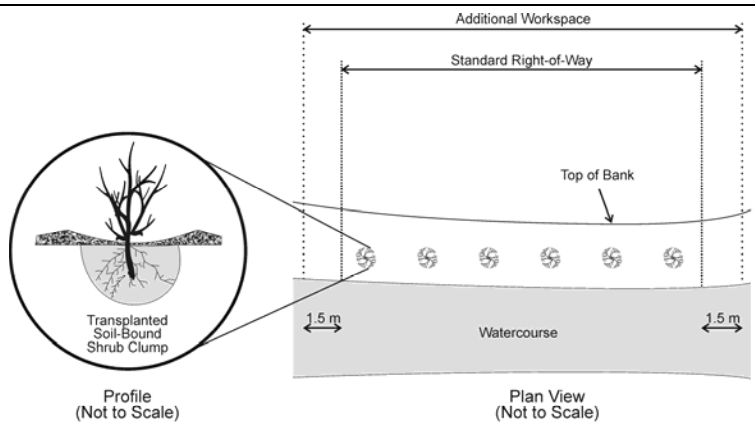
	October 2005
	DWG. NO. 27



Notes:

1. Install stakes of suitable species (*e.g.* willow, dogwood) on watercourse banks.
2. Make clean cuts with unsplit ends using pruning shears, hand saw or chain saw.
3. Select stock from bottom of branches not tips.
4. Mark basal ends to ensure correct installation.
5. Ensure at least one lateral bud above surface and three below. Plant cutting at an angle.
6. Protect material from drying out. Install as quickly as practical.
7. Trim side shoots close to main stock.
8. Use frost pin to make pilot hole. Minimize damage to stake when driving by using a neoprene lined post hole pounder or rubber mallet.
9. Install live stakes on banks and 1.5 m (approximately) back from banks for entire disturbed width of right-of-way.



Notes:

1. Salvage and replace shrubs on all watercourse banks where shrubs are present on the right-of-way.
2. Salvage whole bushes from the right-of-way during grading of banks. Ensure bulk of root mass is surrounded by soil.
3. Store salvaged shrubs on edge of right-of-way, cover with soil and do not let dry out.
4. Transplant as quickly as practical when reconstructing watercourse banks.
5. Soak the ground around the transplant with water.

Source: Adapted from TERA 1998

STREAMBANK PROTECTION – TYPICAL SHRUB RESTORATION

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	October 2005
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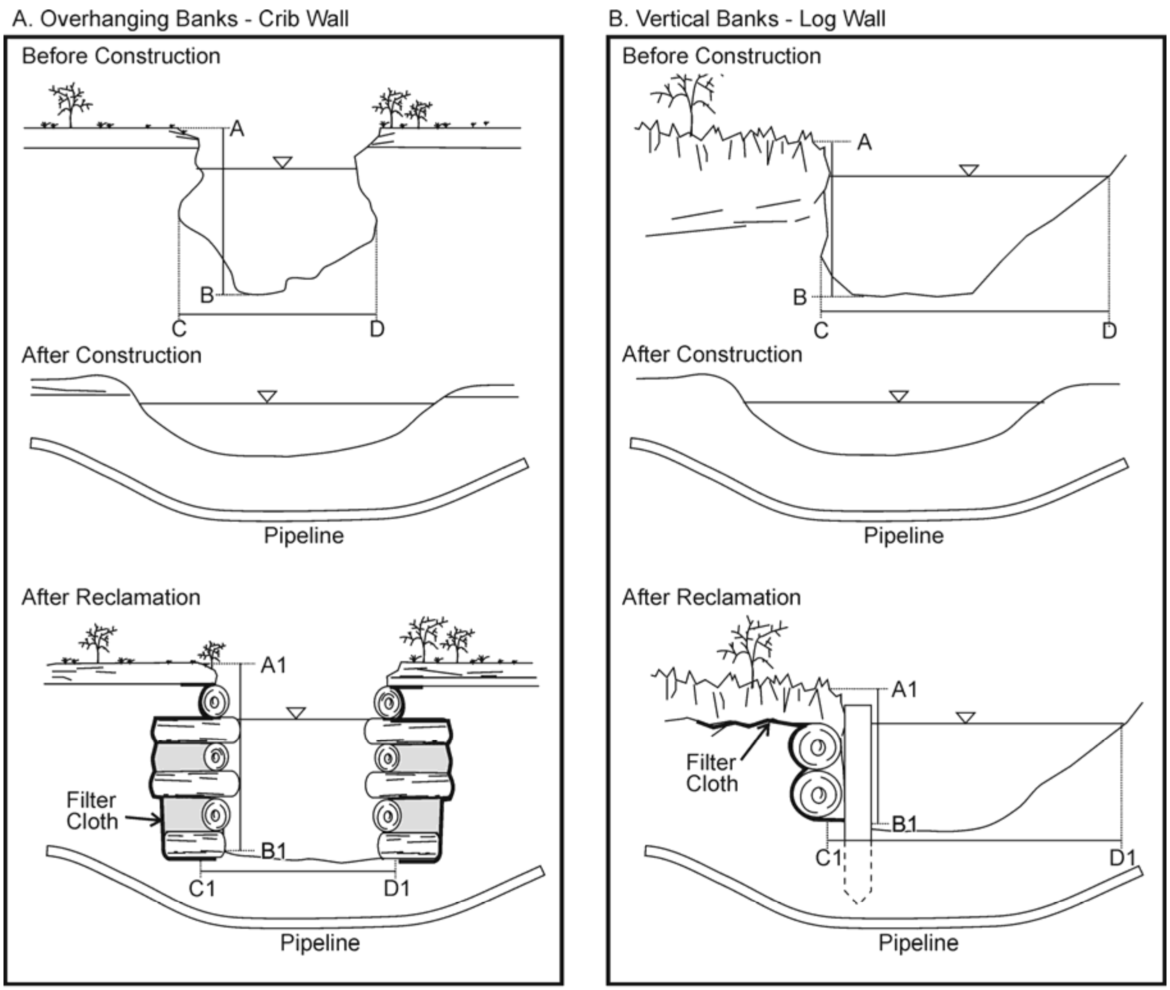

Profile View
(Not to Scale)

Notes - Overhanging Bank Crib Walls:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Install overhanging bank cribwalls to provide overhead cover and erosion control.
3. Install log overhang greater than 30 cm.
4. Install native timber (coniferous where possible).
5. Ensure A1, B1 is not less than A-B.
6. Ensure C1-D1 is not greater than C-D.
7. Backfill with coarse, nonerodible material.
8. Replace subsoil and topsoil.
9. Transplant native vegetation. Sow appropriate seed mix.
10. Live willows may be laid perpendicularly to streamflow within and projecting from the crib wall above the water line. This will create a live crib wall.

Notes - Vertical Bank Log Walls:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Install bank log walls to maintain bank slope and provide erosion control.
3. Install vertical posts 3 times length of exposed height.
4. Utilize native timber or lumber for horizontal structure.
5. Ensure A1-B1 is not less than A-B.
6. Ensure C1-D1 is not greater than C-D.
7. Anchor posts if warranted.
8. Backfill with coarse nonerodible material.
9. Replace subsoil and topsoil.
10. Transplant native vegetation. Sow approved seed mix.
11. Live willows may be laid perpendicularly to streamflow within and projecting from the log wall above the water line. This will create a live log wall.

Source: Adapted from TERA 1998

STREAMBANK PROTECTION – TYPICAL LOG AND CRIB WALLS

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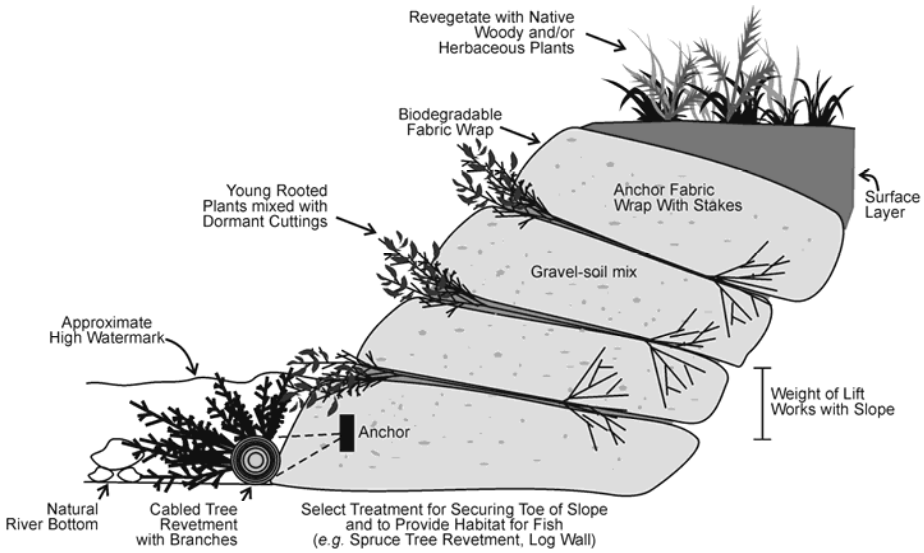
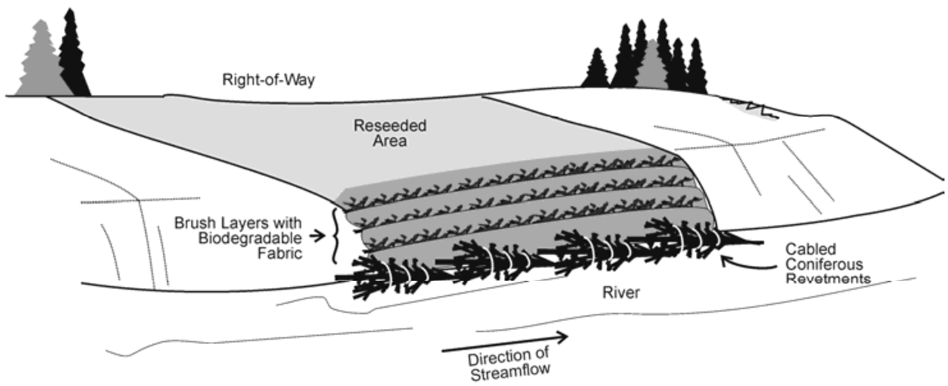
October 2005	
DWG. NO. 29	



Profile
(Not to Scale)



Oblique View
(Not to Scale)

Notes:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Secure the toe of the slope with appropriate technique (coniferous tree revetments, log wall, riprap, etc.).
3. Begin layering at the bottom of slope with first hedge/brush layer situated at the approximate high water mark or lower. Select plant species suitable for site conditions.
4. Excavate the first bench 0.5-1.0 m deep, ensuring not to damage the pipeline, angled slightly down into the slope. Lay branches and transplants on the bench, slightly criss-crossing, with shoots extending beyond the edge of the bench by approximately 20% of their length.
5. Plant 18-25 stems per metre, using higher densities for more erosive sites or if the cutting's diameter is small. Cover with 5-10 cm of soil and tamp into place.
6. Continue building layers with damp soil and cuttings until bank height is reached. Vary spacing between layers based on erosion potential.
7. For best results dig transplants in spring or late summer and plant the same day. Keep transplants moist. A mixture of plant species can mimic adjacent undisturbed vegetation.

Source: Adapted from Alaska Department of Fish and Game 1997

STREAMBANK PROTECTION – TYPICAL HEDGE / BRUSH LAYERING

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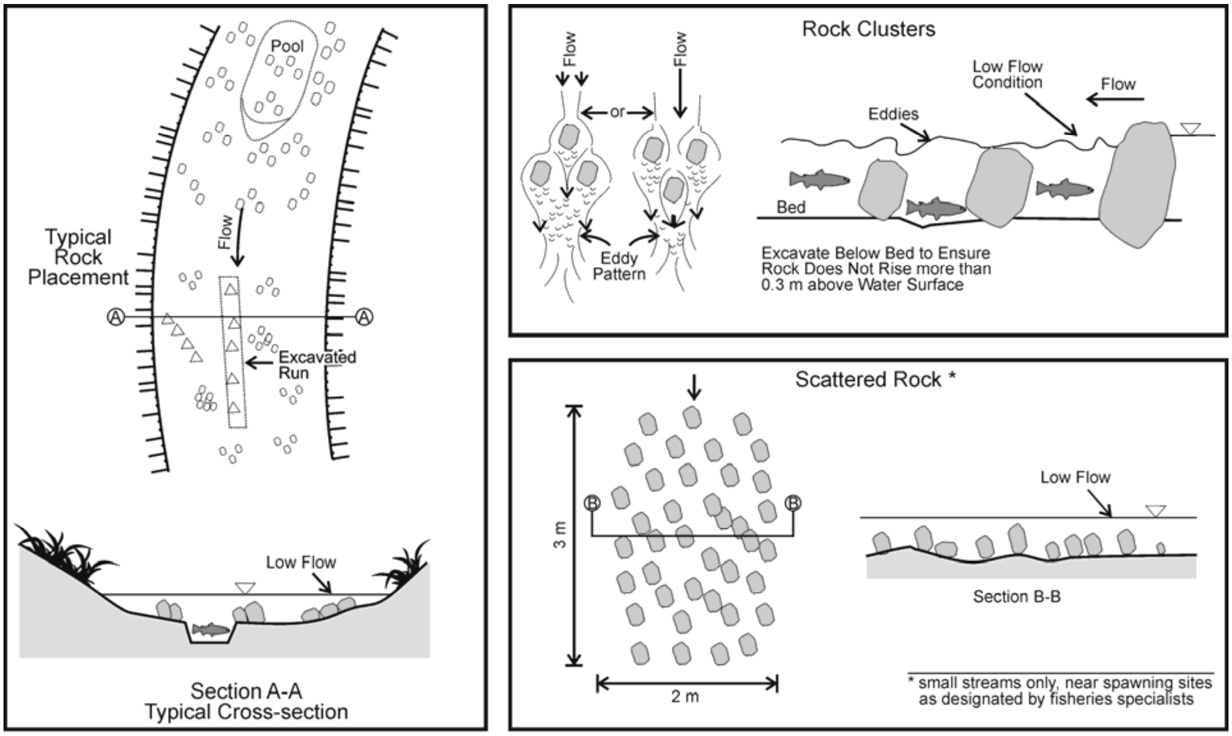

(Not to Scale)

Construction Notes - Rock Clusters (adult shelter):

1. Proper placement and design is critical and qualified specialists should be involved.
2. Navigable Waters approval may be required prior to installing rock clusters.
3. Individual rocks may be in clusters of 2 to 5 (generally 3), placed in various patterns as shown or as directed in the field. Place rocks in the middle 3/4 of the watercourse such that they do not direct current against an existing unprotected bank.
4. Pre-excavate holes so that the rocks are at or below, but not to exceed 0.3 m above existing water level at the time of installation.
5. Arrange the rocks within clusters, averaging 0.8-1.5 m apart, with a minimum space of 2.5 m between each of the clusters.
6. Individual rocks or rock clusters may be placed within a resting pool, excavated run or natural pool or run to enhance shelter and feeding opportunities.
7. For small watercourses, use only small material (0.2-0.4 m) for normal rock clusters. Placement will depend upon flow velocities, depths and location of riffles and pools.
8. For mid size watercourses, large individual rocks are preferred (0.8-1.2 m).
9. For large watercourses (width 50 m) individual rocks in the range of 2.0-3.0 m in diameter are recommended. Exact placement of these rocks is more critical to avoid encouraging bank erosion and specialist advice should be obtained.
10. All rock used must be angular, hard, durable and preferably (not necessarily) weathered for visual acceptance.

Construction Notes - Scattered Rock (Fry Shelter):

1. Proper placement and design is critical and qualified specialists should be involved.
2. Navigable Waters approval may be required prior to installing rock clusters.
3. All rock to be 300 mm or less in diameter, placed in shallow fast moving flow areas such that the top of the rock is at/below normal low water levels.
4. The rock fragment grouping is very loose with an overall size of 2 x 2 m with individual pieces of rock 0.3 m apart.
5. Scattered rock groups to be placed approximately 2.0 m apart, preferably in shallow water near banks to benefit young-of-year and maintain open flow areas.

Source: Adapted from CAPP 1993

INSTREAM COVER – TYPICAL ROCK CLUSTERS

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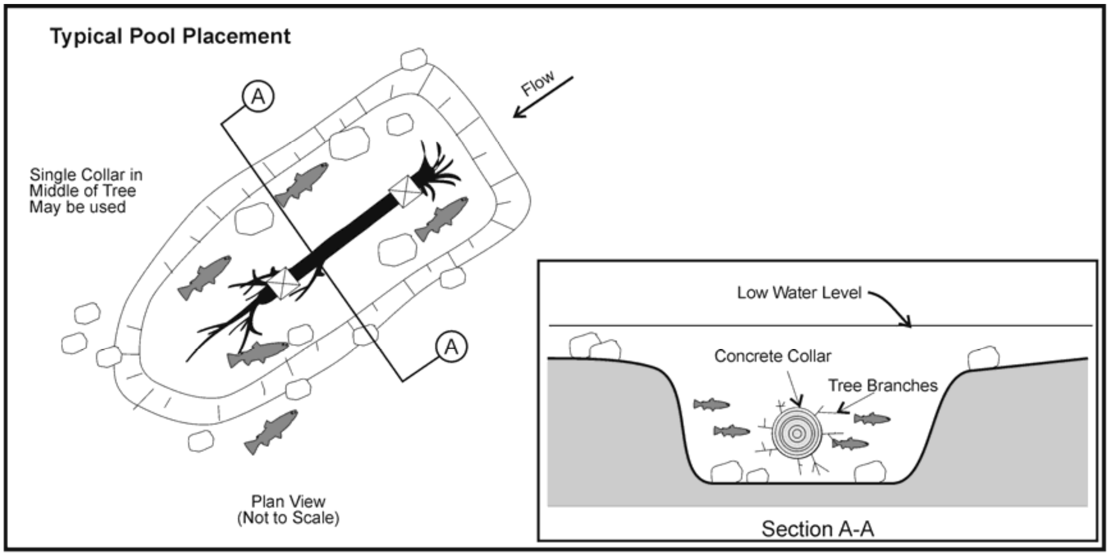
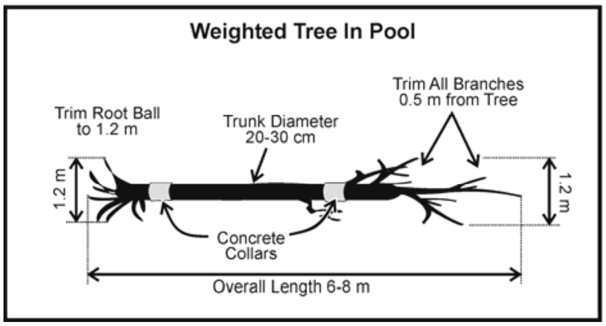
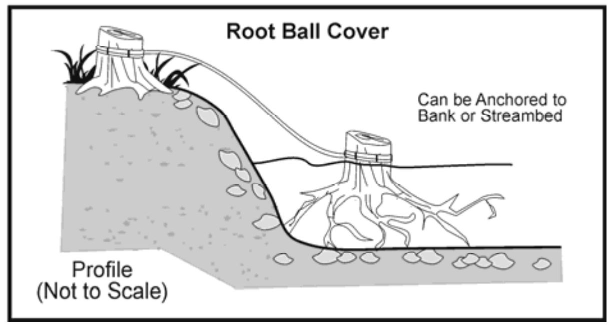






Construction Notes - Weighted Tree in Pool:

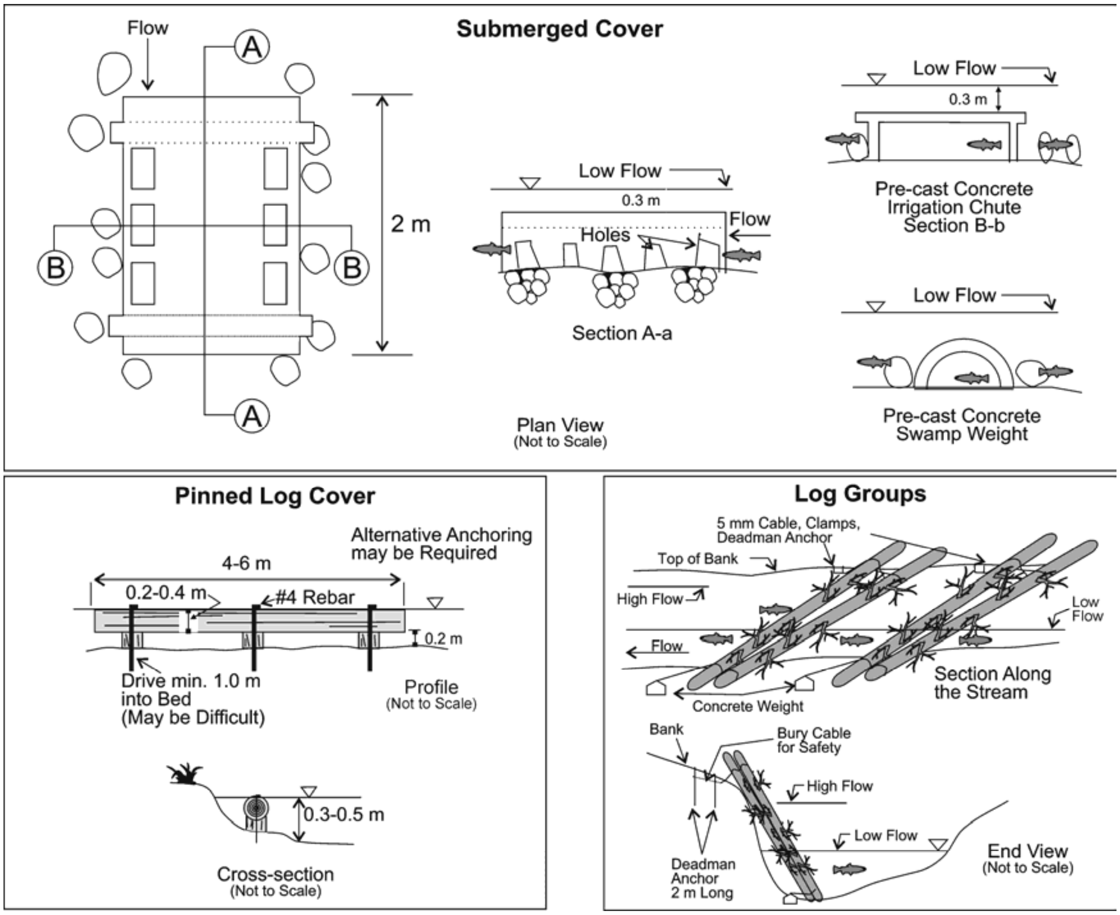
1. Proper placement and design is critical and qualified specialists should be involved.
2. Navigable Waters approval may be required prior to installing log or root balls.
3. Use only sound, straight coniferous trees with adequate branches and root ball, 6-8 m in length, with a minimum diameter of 0.4 m.
4. Trim the root ball and all branches so that they remain 0.6 m below the surface of the pool and will not snag any boat traffic or debris.
5. Place 50 kg or more concrete pipe weights on each end of the tree, where the trunk will support the heavy weights, and move the tree into the pool area utilizing two backhoes, if feasible. Carefully lower the tree to the bottom of the upstream end of the pool (breakage may occur due to heavy pipe weights).
6. Place Rock Clusters in and around the pool as desired.
7. Weighted trees may be added to or removed from pools at any time after construction to change shelter provisions.

Construction Notes -Root Ball Cover:

1. Proper placement and design is critical and qualified specialists should be involved.
2. Navigable Waters approval may be required prior to installing log or root balls.
3. Select and clean large coniferous root balls.
4. Trim and anchor root balls securely to bank or streambed so that they remain 0.6 m below the water surface.

Source: Adapted from CAPP 1993

INSTREAM COVER – TYPICAL LOG / ROOT BALLS



Construction Notes

Submerged Cover

1. Proper placement and design is critical and qualified specialists should be involved.
2. Navigable waters approval might be required prior to installing a submerged cover.
3. Prior to installation, punch several holes in the upper area of the concrete pipe to allow numerous shelter/water interfaces and visual access to the inside of the half pipe.
4. Concrete sections may be set together or placed individually on 2 m triangular steel bars to reduce the amount of settlement into the instream gravels.
5. Place the precast section in the lowest point of the watercourse, parallel to the direction of flow so there will be smooth flow conditions through the pipe section. Water depth at low flow should equal or exceed the structure height.

Pinned Log Cover

1. Proper placement and design is critical and qualified specialists should be involved.
2. Select sound coniferous trees and remove all limbs within 0.2 m from the trunk of the tree and transport to the site.
3. Cut three small logs (0.3 m long) from the tree and drill lengthwise to accept 3/4" reinforcing steel rod. Drill 3 similar holes in the tree to accept the steel rods as shown in the drawing.
4. Select a location, 0.3-0.5 m depth. Place the rebar through main log, and support logs and drive rebar a minimum of 1.0 m into the streambed for good anchorage. Bend the top section of the rebar as shown to anchor the log to the streambed. Additional rebar may be warranted. An alternate anchoring system may be reqired if unable to drive the reinforcing steel into the streambed.

Log Groups

1. Proper placement and design is critical and qualified specialists should be involved.
2. Select sound straight coniferous trees, remove tree limbs 0.3 m from the trunk and transport to the site.
3. Select 2-3 trees and tie into a loose bundle. Overlap the tree lengths by at least 1/2 their length or more.
4. Cable log tips to a 20 kg (or more) concrete weight, which will be placed on the streambed to hold the tips in place.
5. Anchor the base of the logs on the bank with a 5 mm tieback cable to several deadman anchors to prevent movement. Bury the cable tieback to avoid safety hazard to fishermen.
6. Log groups can also be placed with rock clusters by using a short log deadman anchor buried beneath a large rock (1.5 m+) in the middle of the streambed. The log groups are oriented in the downstream direction.

Source: Adapted from CAPP 1993

INSTREAM COVER – TYPICAL SUBMERGED COVER

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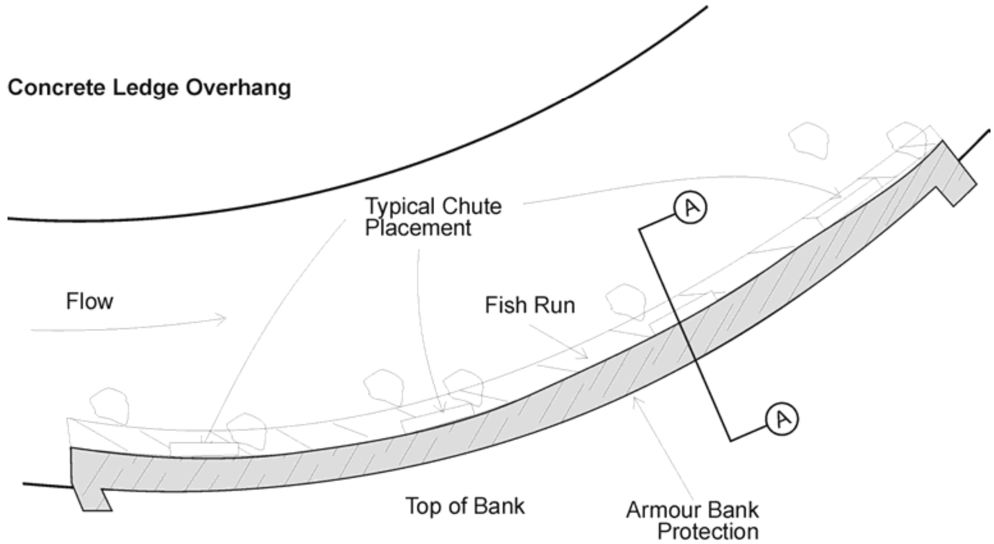
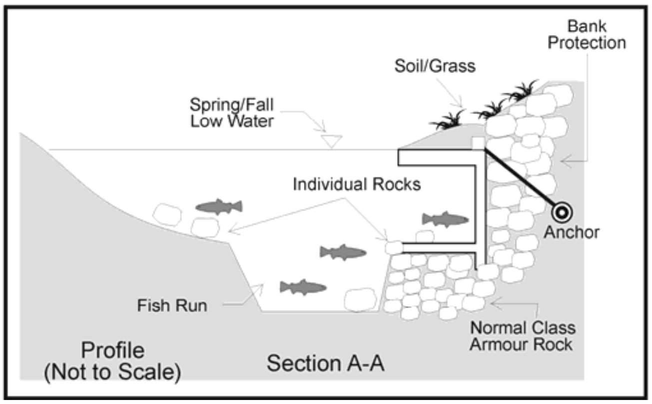


Plan View
(Not to Scale)

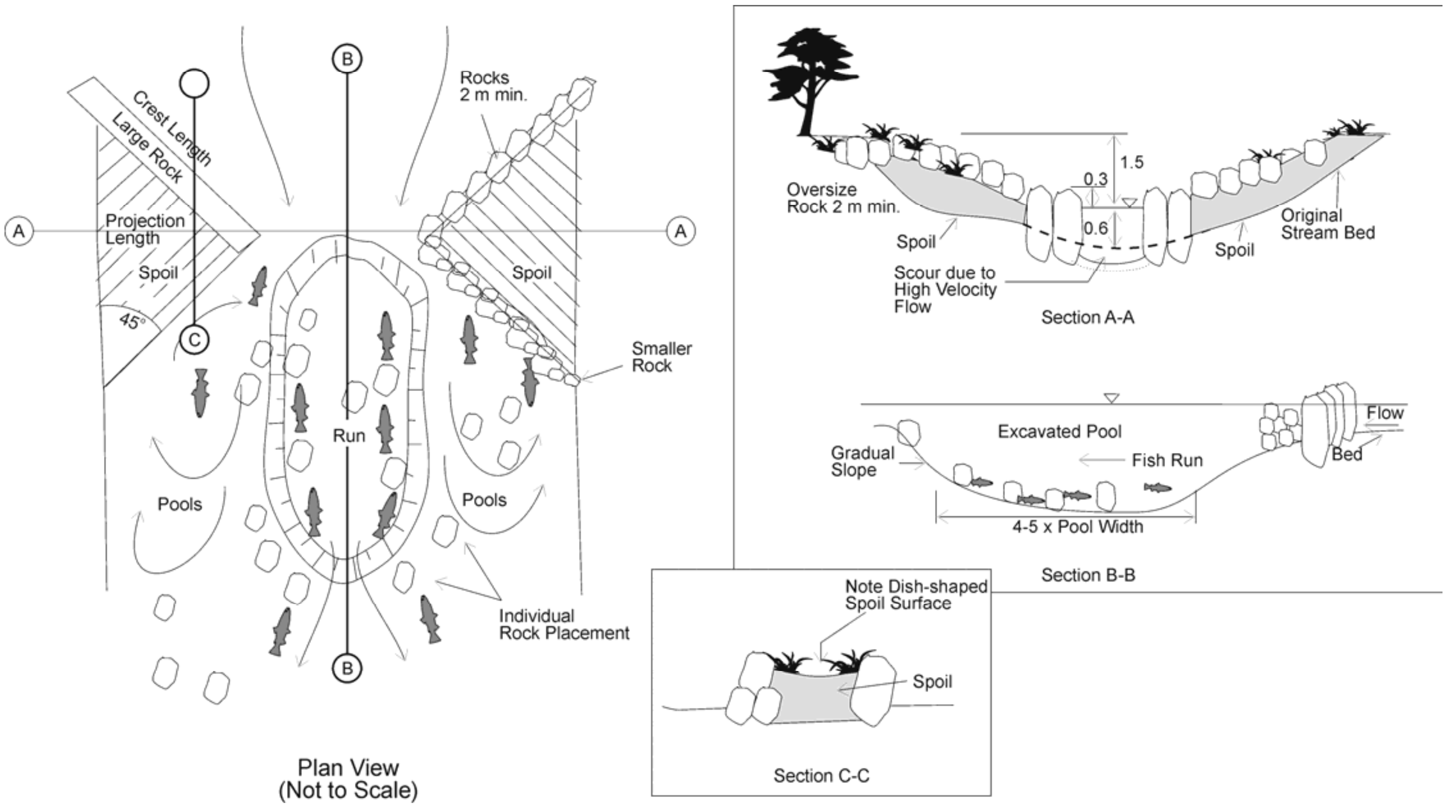


Construction Notes - Concrete Ledge Overhang:

1. Navigable Waters approval might be required prior to installing bank overhang.
2. Proper placement and design is critical and qualified specialists should be involved.
3. If the Concrete Ledge section is added before bank armour rock installed is complete, place only lower portion of rock upon which concrete chute sections will rest. Install all necessary tiebacks, anchors and individual rocks within the flume, taking great care that the flume sections line up horizontally and are well supported.
4. If the flume section is added to an existing armour rock bank, keep the disturbance of the armour rock to a minimum, removing only enough rock to set the flume sections firmly in place. Install the needed tiebacks, anchors and individual rocks within the flume, ensuring the flume sections line up horizontally.
5. Replace the armour rock around the back and ends of the chute, ensuring that no change in horizontal alignment takes place.
6. Backfill the top of the structure with light armour rock. Add soil grass and trees where possible on or near the embankment.
7. This structure may be placed at any location whether there is existing bank protection or not. The method of construction will keep the disturbance of the armour rock to a minimum.
8. Maintenance may be required to maintain proper horizontal alignment of the sections to avoid damage occurring to the structure when a strong current catches an edge separation.

Source: Adapted from CAPP 1993

INSTREAM COVER – TYPICAL BANK OVERHANG



Construction Notes:

1. Navigable Waters approval might be required prior to installing opposing rock wing deflectors.
2. Proper placement and design is critical and qualified specialists should be involved.
3. All rocks must slope down to the middle of the watercourse to the point of the deflector.
4. The upstream face must contain the largest rocks so that the pressure of the flow may be resisted. Smaller rocks may be placed on the downstream face. Each rock is to be placed in the shadow of the previous rock from the point to the bank. All rock must fit tightly together and be jammed together by machinery.
5. Place the upstream rock face in a trench, then place the downstream rock face in a similar trench, taking care that the rocks slope upwards to the side of the watercourse such that the point of the deflector is about 0.3 m above the water level and the root is at least 1 to 1.5 m above current water level. Ensure the pipeline is not damaged during this excavation.
6. Excavate the downstream run, placing much of the spoil material within the confines of the two rock faces. The top surface of the spoil must be below the level of the adjacent rock faces. All remaining spoil must be deposited 10 m outside the streambanks and preferably 1.5 m above the water level.
7. In very large watercourses, a double row of rocks will be required for both the up and downstream faces of the deflectors.
8. The open area in the middle of the watercourse must be about 1/4 of the watercourse width or less, so that a section of the rapid flow conditions exists to funnel the water into the downstream run. On occasion the opening must be constricted even more to provide higher flow velocities when necessary.
9. The instream point of the deflectors shall be 0.6 m above the streambed. Ensure that the root of the deflectors is 1.0 to 1.5 m above current water levels and firmly imbedded in the streambank.
10. All elevations relate to low streamflow in the spring or fall.

Source: Adapted from CAPP 1993

CURRENT DEFLECTORS – TYPICAL OPPOSING ROCK WING DEFLECTORS

CAPP • CEPA • CGA

Third Edition

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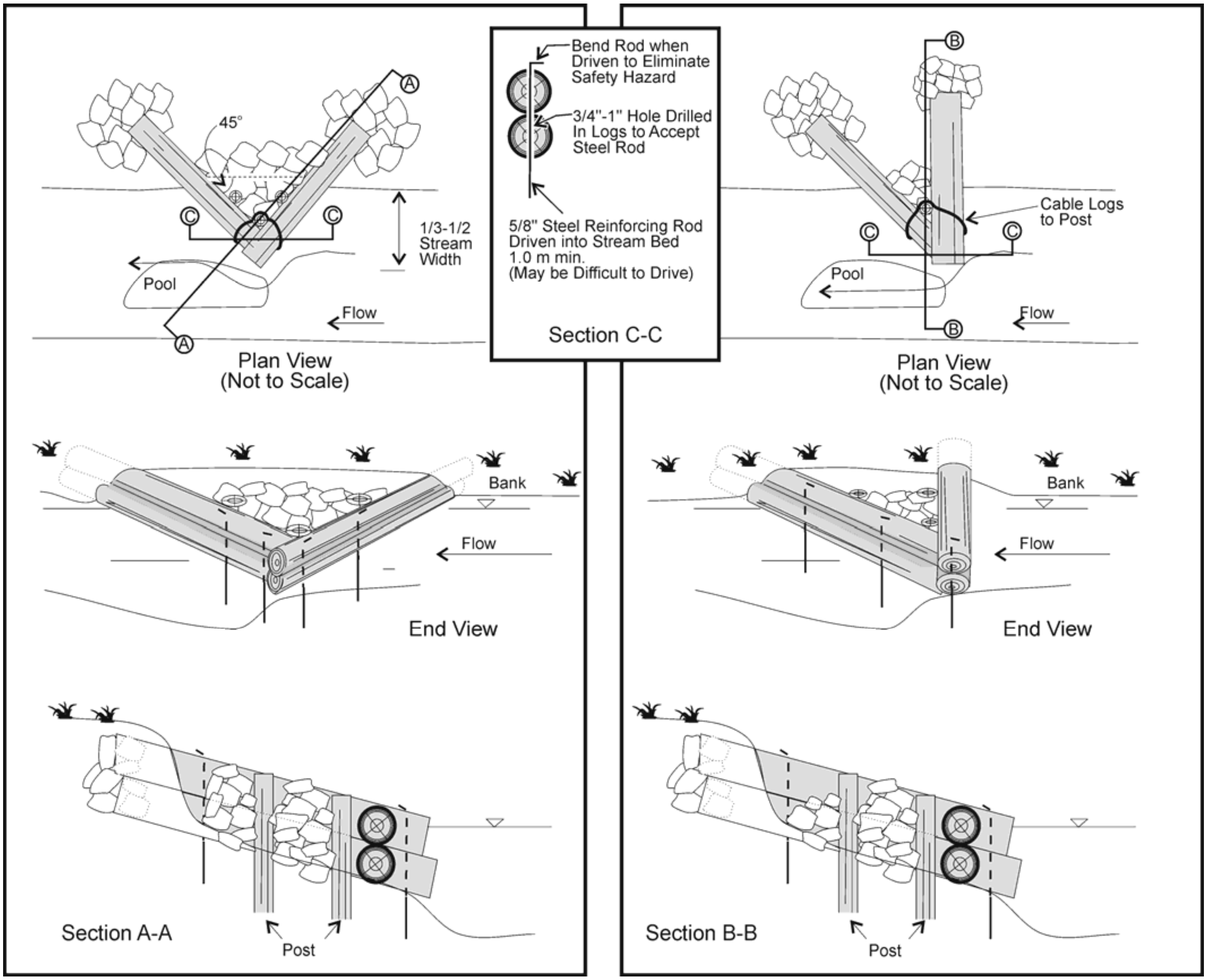

Construction Notes:

1. Navigable Waters approval might be required prior to installing a log deflector.
2. Proper placement and design is critical and qualified specialists should be involved.
3. Select sound, straight coniferous trees; trim all branches; debark all logs and transport to the site. Cut logs to the required length.
4. The main deflector logs are set into a pre-excavated trench in the streambed. The base of the logs must be on the bank, and the points of the deflector on the streambed. Where only smaller logs are available, one log is set on top of another and pinned together for support and correct alignment. A 15 cm (minimum) diameter post is to be driven deeply into the streambed at the inside point of the deflector logs for additional support. The logs may also be pinned to the streambed with reinforcing steel.
5. The deflector logs must extend from a low point in the watercourse (about 1/3 to 1/2 the watercourse width) up and into the banks a distance of 1.5 - 2 m. Additional logs are placed on top of the initial logs if necessary and pinned to the bottom log and cabled to the post for additional support.
6. Place large rocks around and against the base of the deflector logs and on the inside point to hold them firmly in place.
7. The top of the log deflector shall not be more than 0.6 m above the streambed, unless a more effective deflector is required.

Source: Adapted from CAPP 1993

CURRENT DEFLECTORS – TYPICAL LOG DEFLECTOR (Small Watercourses, Width <5 m)

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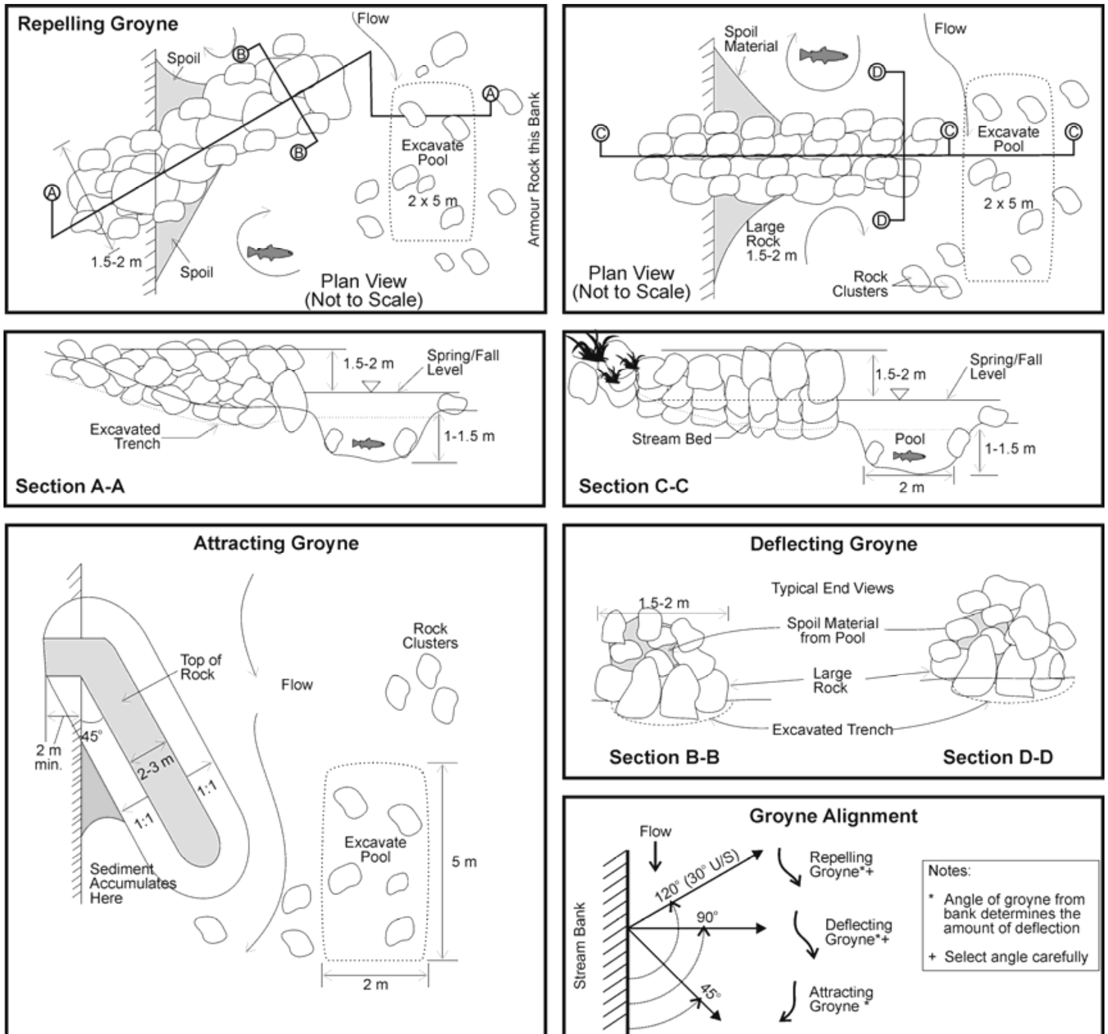


Construction Notes:

1. Navigable Waters approval might be required prior to installing a groyne.
2. Proper placement and design is critical and qualified specialists should be involved.
3. The largest rocks are always to be placed at the tip of the groyne.
4. Projecting length must not exceed 1/2 watercourse width.
5. Groynes are always to be countersunk into the bank.
6. Only a minimum amount of spoil material is to be placed on the groyne to fill holes and soften appearance. All remaining spoil material is to be placed 10 m outside the channel.

Repelling Groynes - 30° upstream

1. Deflects the main current toward the opposite bank. Heavy armour bank protection is required on the opposite bank.
2. This structure will protect a length of eroding bank up to 3.5 times the projecting length. They are normally utilized to deflect flows away from an eroding bank under severe erosion conditions, large flows or unstable banks.

Deflecting Groynes - 90° to the bank

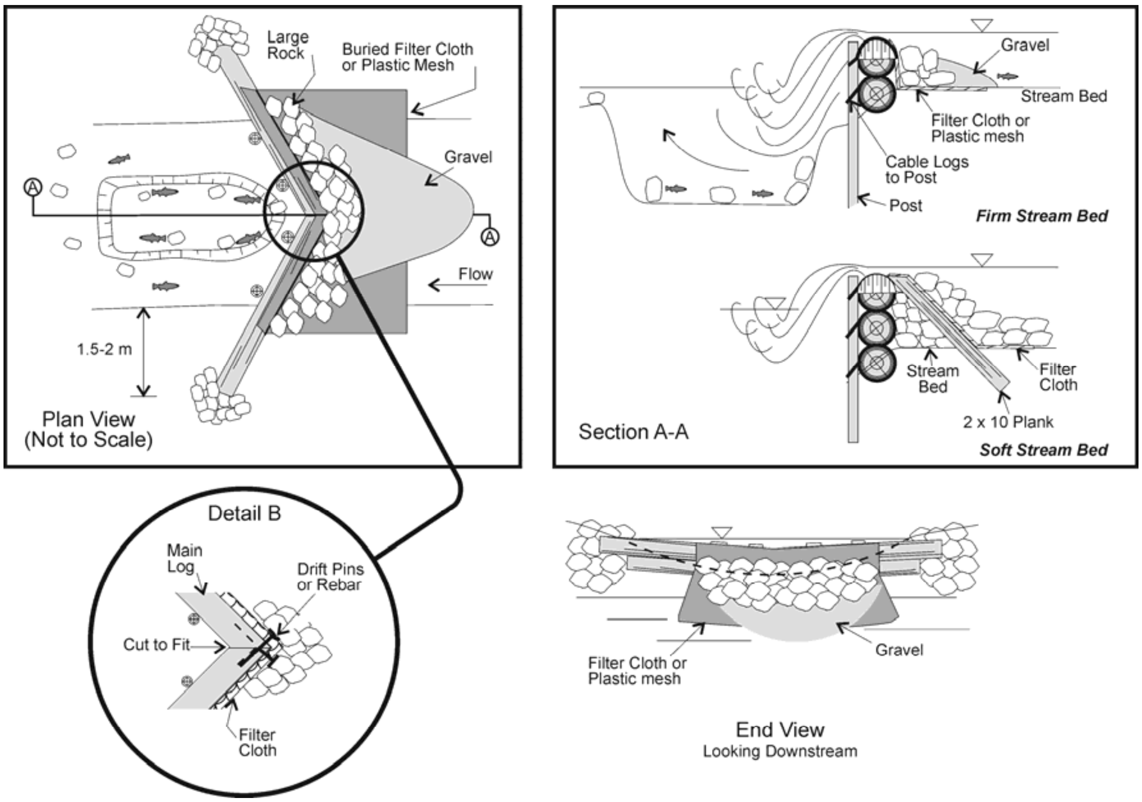
1. Deflects the current from along the bank into mid-stream away from the groyne. The opposite bank requires protection when the projection length approaches 1/2 the watercourse width. These are used to provide economical channel narrowing in wide shallow reaches.
2. Typical design is a series of groynes, each 3 m long at 10 m spacing around the outside bend of a watercourse, with a small pool at the tip of each groyne. Excavated material from fish runs must be properly spoiled or placed on the bank between groynes.

Attracting Groyne - 45° downstream

1. Deflects flow slightly, pulling it downstream behind the groyne.
2. These are normally used to confine rapid, shallow flow to the middle 1/2 of a watercourse or installed on alternating banks to provide a deeper meandering channel pattern in a straight reach when combined with a large Excavated Run and Rock Clusters.

Source: CAPP 1993

CURRENT DEFLECTORS – TYPICAL GROYNES – FULL SIZE

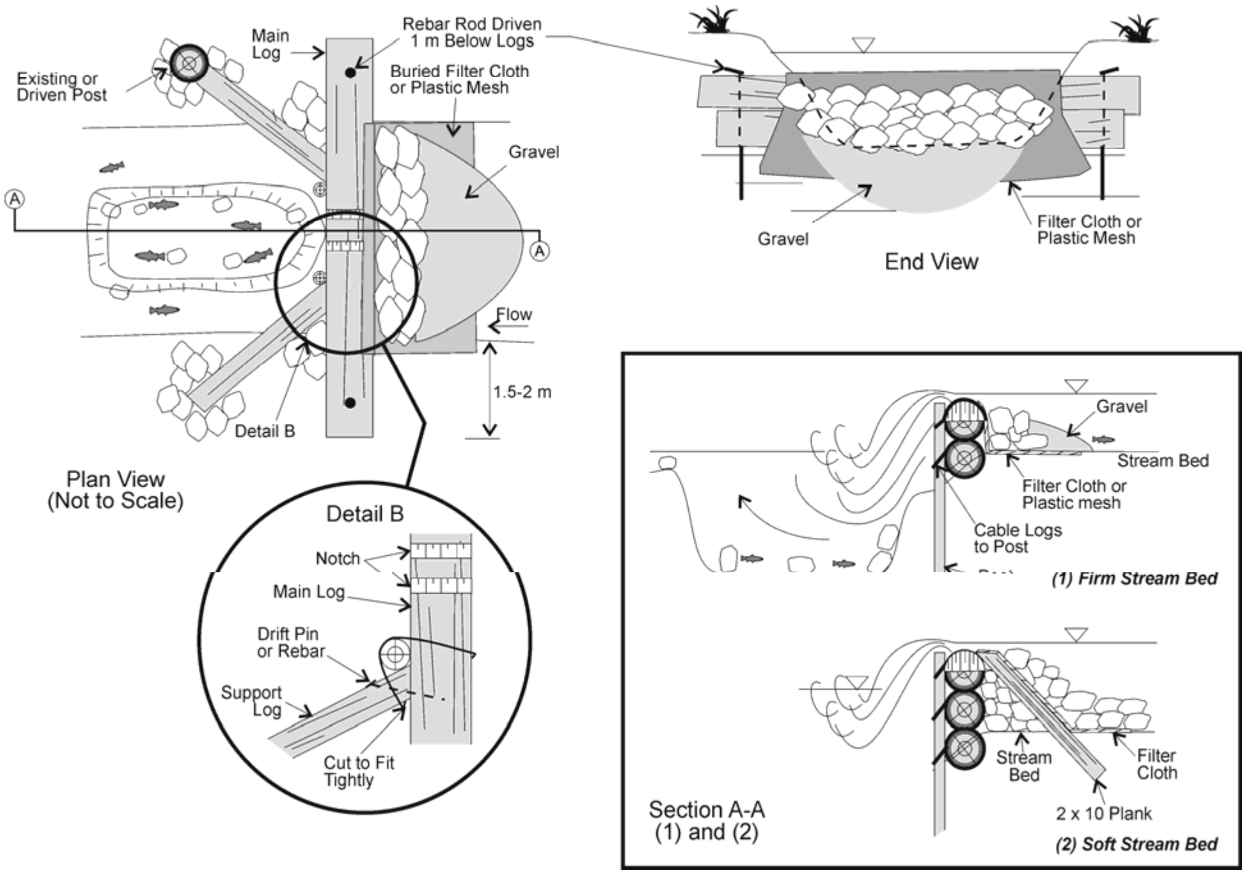


Construction Notes:

1. Navigable Waters approval might be required prior to the installation of a Log V Weir.
2. Proper placement and design is critical and qualified specialists should be involved.
3. Select sound, straight coniferous trees for all main and support logs, trim all branches, debark all logs and transport to the site.
4. Main support logs are set into a pre-excavated trench (avoiding the pipeline) in the streambed and must slope down to the middle of the weir to confine the flow to the middle of the watercourse. Where the selected logs are small in size two layers are required. One layer is set on top of the bottom layer and pinned together as needed for stability. Four to six, 15 cm diameter posts are to be driven deeply into the streambed on the downstream side of the weir crest for additional stability. Two posts are located near the notch while the others are spaced out along the weir crest. The posts are tightly cabled and pinned to the main logs for additional support.
5. Main support logs must extend upstream against the direction of flow from the banks to the middle point of the weir. The logs are deeply buried in the banks for a distance of 1.5-2 m.
6. The central logs are pinned together with drift pins driven through one log into the opposite log. Posts are pinned to the main logs.
7. Approved filter cloth is attached to the upstream side of the main logs and extended down to the streambed. The filter cloth is then extended upstream at least 2 m. This filter cloth will prevent the migration of cobbles beneath the log structure. This migration of cobbles is to be avoided at all costs since it eliminates the effectiveness of the structure. Repairs will center on this area.
8. Large rocks (0.5 m) are placed on the filter cloth against the main logs to keep the cloth and logs in place. Smaller material (cobbles) is placed on and upstream of the rocks to provide a smooth upstream bed surface and fill in the voids.
9. An alternative is to place short (0.75 m) pieces of 2" x 10" planking extending from the weir crest upstream and down into the channel bed to form a barrier to movement of material similar to the cloth described above. It is recommended to add the cloth as well. The space under the planking is filled with rock and cobbles to eliminate any voids.
10. The upstream notch on the weir must be within the middle third of the watercourse, but may be placed at any point within to move the current from side to side. Bank armouring may be needed in such cases.
11. The top of the log sill at the notch of the weir is not to be more than 0.6 m above the streambed, unless a deeper upstream pool is required. Locate the bank tie-in 1.0 m+ above the watercourse elevation or 0.5 m above the notch. Ensure that logs shall taper gradually from the notch to the tie-in point on the bank.

Source: Adapted from CAPP 1993

OVERPOUR STRUCTURES – TYPICAL LOG V WEIR (Small Watercourses, Width <5 m)

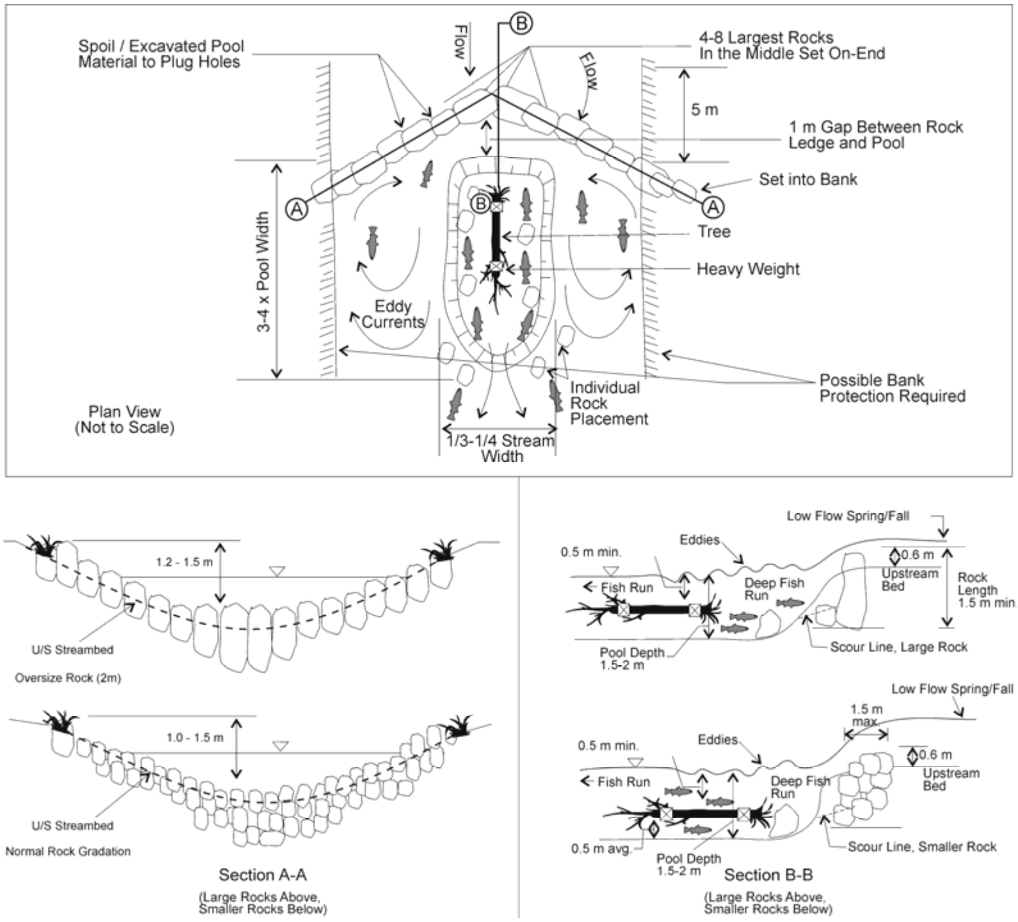


Construction Notes:

1. Navigable Waters approval might be required prior to the installation of a Log K Dam.
2. Proper placement and design is critical and qualified specialists should be involved.
3. Select sound, straight coniferous trees for all main and support logs, trim all branches, debark all logs and transport to the site.
4. Main support logs are set horizontally into a pre-excavated trench in the streambed. Where only small logs are available, one log is set on top of another and pinned together for support and correct alignment. Fifteen centimetre diameter posts are to be driven deeply into the streambed on the downstream side of the weir crest for additional stability. The posts are tightly cabled to the main logs for support.
5. The main weir crest log must extend across the watercourse and into the banks a distance of 1.5-2 m. Additional logs are placed on top and pinned to the bottom log and cabled to the posts.
6. The support logs are pinned to the main log with long nails.
7. Approved filter cloth is attached to the upstream side of the main log and extended down to the streambed. The filter cloth is then extended upstream at least 2 m. This filter cloth will prevent the migration of cobbles beneath the log structure. This migration of cobbles is to be avoided at all costs since it eliminates the effectiveness of the structure.
8. Place large rocks on the filter cloth against the main log to keep the cloth and log in place. Smaller material (cobbles) is placed on the upstream of the rocks to provide a smooth upstream bed surface and fill in the voids.
9. An alternative is to place short (0.75 m) pieces of 2" x 10" planking extending from the weir crest upstream and down into the channel bed to form a barrier to movement of material similar to the mesh described above. It is recommended to add the cloth as well. The space under the planking is filled with rock and cobbles to eliminate any voids.
10. The top of the log sill is not to be more than 0.6 m above the streambed, unless a deeper upstream pool is required. A notch is to be cut in the middle of the weir crest to concentrate very low discharges. The notch is to be less than 1/2 the top log depth and about 0.4 m wide measured at the top of the log (see drawing).

Source: Adapted from CAPP 1993

OVERPOUR STRUCTURES – TYPICAL LOG K DAM (Small Watercourses, Width <5 m)

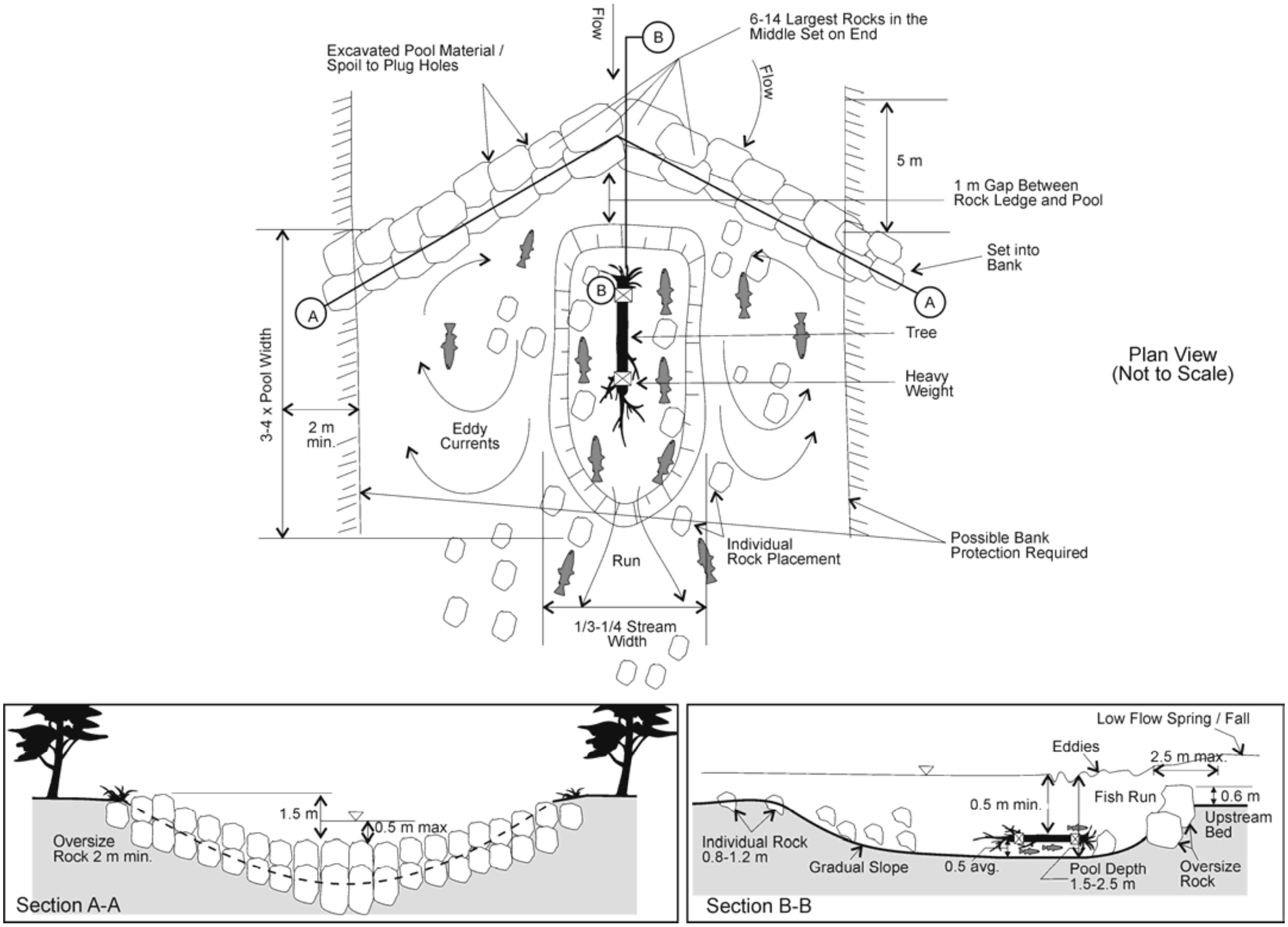


Construction Notes:

1. Navigable Waters approval might be required prior to the installation of a Single Crest V Weir.
2. Proper placement and design is critical and qualified specialists should be involved.
3. All weir crest rocks must slope down from the banks to the upstream point of the weir to confine the main flow to the middle 1/3 of the watercourse.
4. All rock must extend upstream from the bank where they are buried deeply to the middle point of the weir.
5. The largest (4-8) rocks must be placed at the point of the weir and set in place with the longest side pointing down (as shown) in a trench already excavated for this purpose. All rock is to be jammed together by machinery to provide tight-as-practical fit. Additional stabilizing rocks and spoil are to be placed around these rocks. Then the remainder of the weir crest may be built. The weir crest width should be 1.5 m wide.
6. The upstream notch on the weir must be within the middle third of the watercourse, but may be placed at any point within to move the current from side to side. Bank armouring may be necessary in such cases where potential bank erosion exists.
7. The top of the rocks in the notch of the weir is not to be more than 0.6 m above the streambed, unless an upstream pool is required. The bank tie-in location is to be 1.5 m above the watercourse elevation. Ensure that the rocks taper gradually from the notch to the tie-in point on the bank.
8. Only a minor amount of spoil material may be used to fill in the voids in the weir crest to prevent water from flowing through the weir. The spoil is only to ensure relative water tightness. All remaining spoil material must be placed 10 m beyond the streambanks, preferably 1.5 m above current water level.
9. All elevation differences shall relate to the low streamflow conditions in the spring or fall, or at time of inspection, whichever is less.
10. All individual placed rocks to be a uniform size.
11. Pool depth to be 1.5-2.0 m maximum due to watercourse width.

Source: Adapted from CAPP 1993

OVERPOUR STRUCTURES – TYPICAL V WEIR - SINGLE CREST (Small Watercourses)



Construction Notes:

1. Navigable Waters approval might be required prior to the installation of a Double Crest V Weir.
2. Proper placement and design is critical and qualified specialists should be involved.
3. All weir crest rocks must slope down from the banks to the upstream point of the weir to confine the main flow to the middle 1/3 of the watercourse.
4. All rock must extend upstream from the bank where they are buried deeply to the middle point of the weir.
5. The largest (8-16) rocks must be placed at the point of the weir in a double row and set in place with the longest side pointing down (as shown) in a trench already excavated for this purpose. All rock is to be jammed together by machinery to provide tight as practical fit. Additional stabilizing rocks and spoil are to be placed around these rocks. Then the remainder of the weir crest may be built. The weir crest width should be 2.0 m wide.
6. The upstream notch on the weir must be within the middle third of the watercourse, but may be placed at any point within to move the current from side to side. Bank armouring may be necessary in such cases where potential bank erosion exists.
7. The top of the rocks in the notch of the weir is not to be more than 0.6 m above the streambed, unless an upstream pool is required. The bank tie-in location is to be 1.5 m above the watercourse elevation. Ensure that the rocks taper gradually from the notch to the tie-in point on the bank.
8. Only a minor amount of spoil material may be used to fill in the voids in the weir crest to prevent water from flowing through the weir. The spoil is only to ensure relative water tightness. All remaining spoil material must be placed 10 m beyond the streambanks, preferably 1.5 m above current water level.
9. All elevation differences shall relate to the low streamflow conditions in the fall, or at time of inspection, whichever is less.
10. All individual placed rocks to be a uniform size.
11. Pool depth to be 1.5-2.5 m maximum due to watercourse width.

Source: Adapted from CAPP 1993

OVERPOUR STRUCTURES – TYPICAL V WEIR – DOUBLE CREST (Larger Watercourses)

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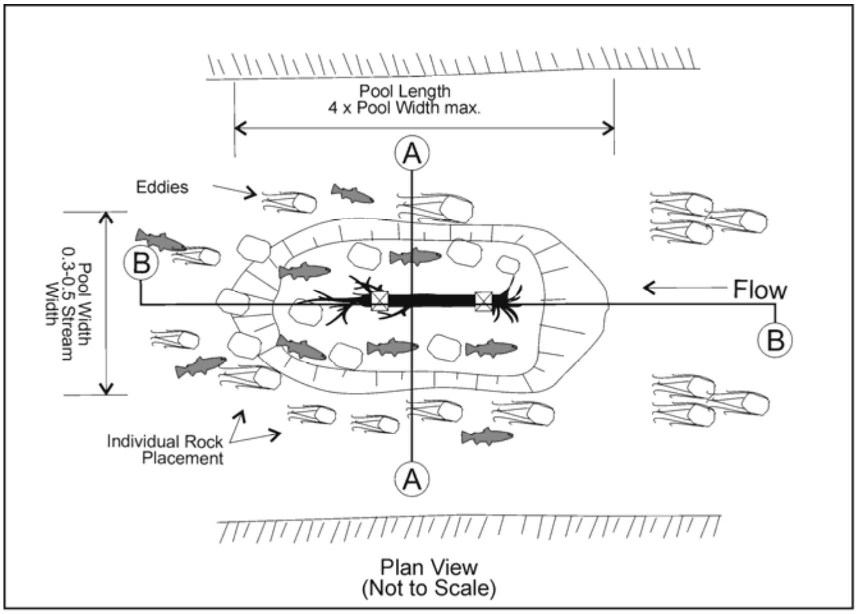
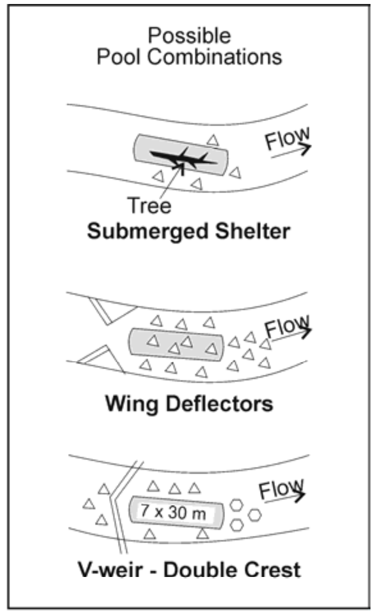
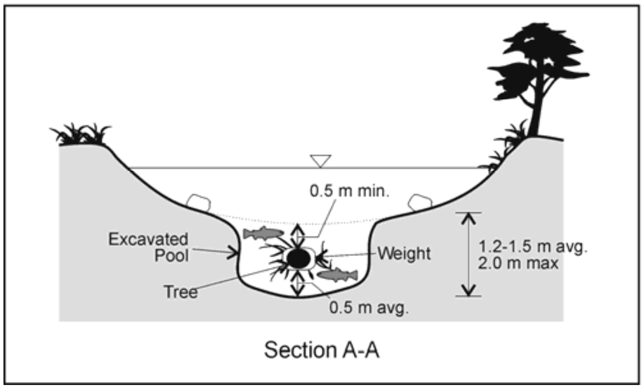
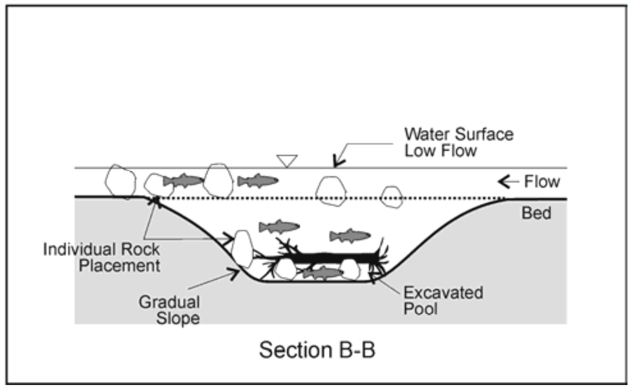


Plan View
(Not to Scale)





Section A-A



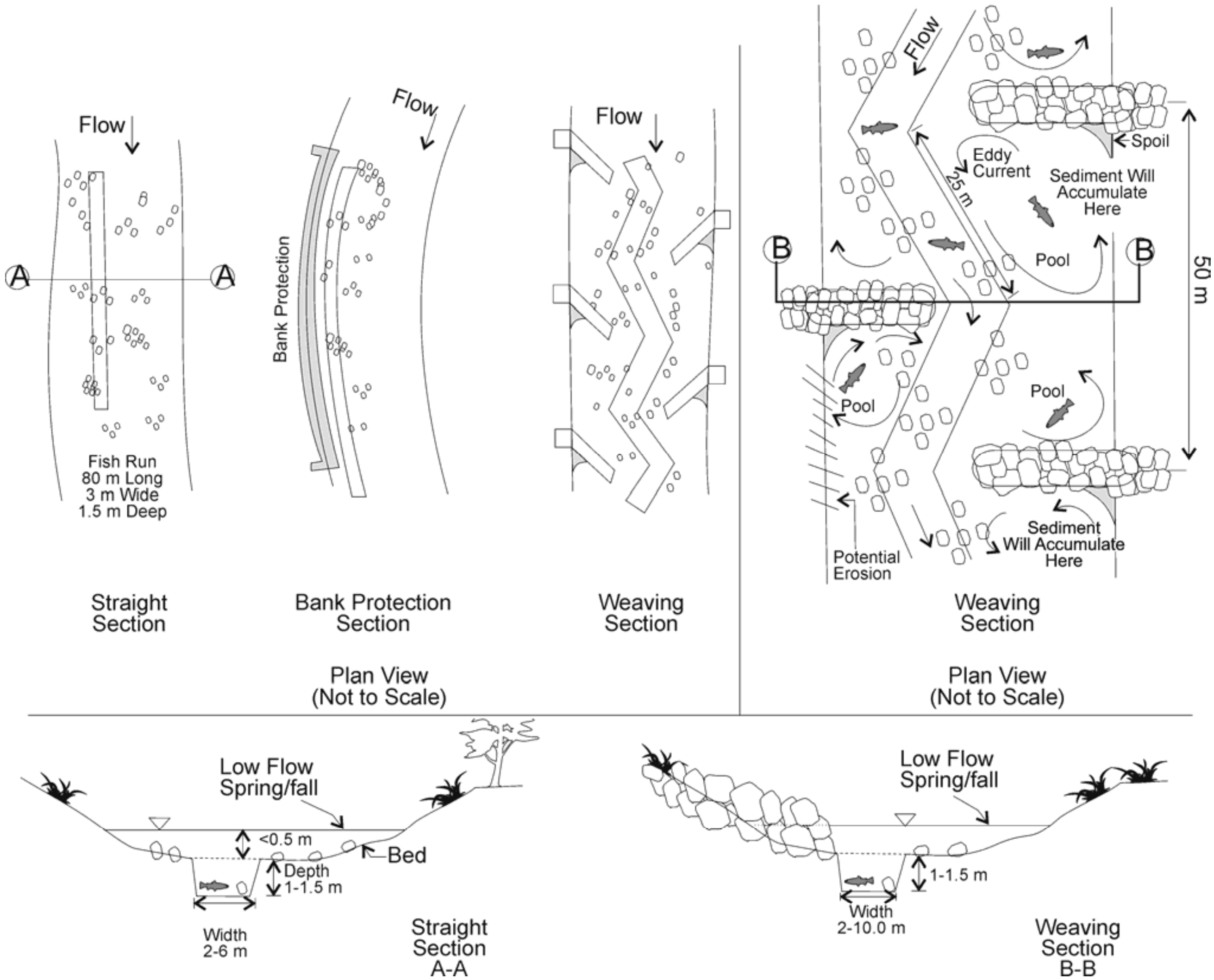
Section B-B

Construction Notes:

1. Navigable Waters approval might be required prior to the installation of a typical resting pool.
2. Proper placement and design is critical and qualified specialists should be involved.
3. Locate the pool in a relatively straight section of the watercourse. Moderate existing depth is best indicator.
4. Centre the pool in the deepest part of the channel.
5. Pool width is not to exceed 2/3 of the channel width.
6. Pool depth must be a minimum of 1.5 m, but not to exceed 2.5 m.
7. Pool length is not to exceed 4 pool widths, normally about 3 times pool width is recommended.
8. Typical pool dimensions range from 2 m x 4 m on a small watercourse to 10 m x 40 m for a large watercourse. Excavations normally produce a water depth of 2 m or greater during low flow conditions in most watercourses, and greater than 2 m in large watercourses.
9. All spoil material is to be placed 10 m outside the channel limits at the time of construction (low flow) preferably in an abandoned dry side channel, a minimum of 1.5 m above current water level. This will avoid the material being washed back into the pool with the first high water.
10. Individual rocks 0.8 to 1.2 m in diameter may be placed at or below but no greater than 0.3 m above current water level at the time of work.

Source: Adapted from CAPP 1993

SUBSTRATE MANIPULATION – TYPICAL RESTING POOL



Construction Notes:

1. Navigable Waters approval might be required prior to the installation of an excavated fish run.
2. Proper placement and design is critical and qualified specialists should be involved.
3. Excavated run is located within the middle 1/2 of the watercourse, crossing the deepest section, or as directed in the field.
4. The excavated run is composed of several straight sections, placed at angles to each other to provide a deep meandering channel in an otherwise straight, wide and shallow reach.
5. Individual rocks or rock clusters may be placed within the excavated run (width permitting) or along the outside to deflect the main current into the excavated run and maintain higher velocities to reduce sediment deposition within the trench.
6. With this structure, care of spoil is important since improperly disposed of material could easily be swept back into the excavated run. Spoil material is to be removed 10 m from the channel, 1.5 m above current water level.
7. Excavated run structures may be accompanied by rock clusters, deflectors and overhang structures to provide high quality habitat.

Source: Adapted from CAPP 1993

SUBSTRATE MANIPULATION – TYPICAL EXCAVATED FISH RUN

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Appendix B Watercourse Crossing Case History Summaries

The following summarizes 326 case histories of open cut, dam and pump, flume, temporary diversion and two-stage coffer dam watercourse crossings that have been taken from TERA Environmental Consultants (Alta.) Ltd. (1996) with the exception of directional drilling, which was taken from P.A. Harder and Associates Ltd. (1995).

Open Cut Case History Summary

Fifty-nine examples of open cut crossings are summarized. These examples discuss water crossing construction at various sized watercourses using the plow, hoe, clamshell dragline, yo-yo dragline and dredge techniques.

All small watercourses (<10 m wide) were excavated by hoes with the exception of one which was plowed-in. Construction of all small watercourses were completed in less than one day with the exception of the plowed-in crossing, which required an extra day for bank preparation. Sedimentation and water quality were monitored at several crossings. No detectable changes in water chemistry or composition of streambed materials were recorded when the plow method was used. A dramatic increase in suspended sediments and increased benthic drift were reported during an open cut crossing with hoe excavation. However, it was concluded that the negative impacts to the benthic community were limited to the period immediately following construction and no negative impacts on the benthic community were detected after peak spring flow.

All medium-sized watercourses (10-20 m in width) were excavated with hoes, although draglines were used to assist at three crossings. Most crossings of this size were completed in two days. However, four days were required where trucking of spoil was conducted and three additional days were needed when blasting was required.

A high suspended sediment load was common in those crossings which were monitored for TSS or turbidity as well as those with anecdotal observations. One crossing with very coarse sediments had a "very large percentage" of sediment deposited within the first 200 m, while another in coarse sediments indicated that construction did not result in a significant sediment load. Other observations indicated that after 24 hours very little or no sediments remained in suspension and that, in general, most impacts seemed to be very short-lived and substrate composition returned to preconstruction conditions within nine months. Only two references to biotic impact are referenced in the case histories for open cut trenching. One monitoring program found that after one month there had been no significant increase in mountain whitefish egg mortality downstream of the crossing and juvenile whitefish continued to use pool habitats. It was also noted that although the high level of suspended solids was injurious to some fish, the relatively short-term nature of the disturbance minimized effects on downstream fish. Another anecdotal comment points out that extra time spent trucking spoil offsite resulted in increased instream activity that likely caused more disturbance than would have occurred with instream spoil storage.

Large watercourses, over 20 m in width, are constructed with a variety of methods. Of 22 open cut trenching examples in watercourses ranging from 20 m to 1000 m in width, hoes were generally used to excavate the trench. However, clamshell draglines, yo-yo draglines and dredges were also commonly used. The length of instream activity ranged from 1 day for 40 to 60 m wide crossings, to 60 days working 24 hrs/day for an 885 m wide crossing. Most watercourses less than 50 m in width took 1-3 days. Those crossings that took longer than one week tended to have adverse conditions such as extreme width (885 m) and very sandy substrates (60 days); very steep and long approach slopes (6 weeks); or a deep channel requiring construction of pads for hoes (2.5 weeks).

The comments related to impacts on biotic resources and water quality at larger water crossings were similar to those of smaller watercourses.

In general, open cut crossings are always successful although they range in difficulty and the degree of success. No examples of abandoned attempts of open cut crossings were encountered. Those crossings which were well constructed and successful were well planned, had sufficient equipment onsite, had experienced crews and were completed in as little time as practical. Crossings tended to have low success where: the floodplain or staging area was too wet or too small, the substrates were too soft or sandy, the contractor was disorganized and had no plan, there was an inappropriate use of instream sediment control devices; poor advice from inspectors and government representatives undersized equipment; or flood conditions.

Dam and Pump Case History Summary

Thirty examples of the dam and pump water crossing method were considered in the case history summary.

The dam and pump method was most commonly used on watercourses that were less than 10 m in width although examples of watercourses 15, 30 and 75 m in width are also summarized. In most cases, dams were constructed with conventional sandbags, although the larger 1 m^3 sandbags have been used in many of the higher energy watercourse crossings in British Columbia. One example of an aquadam is cited. Pea gravel bags used in conjunction with an impermeable liner have been used in several U.S. crossings. One company in southern Ontario as well as contractors in Alberta made many of their dams from plate steel pressed into the bed and banks, effectively sealing the streamflow. Other examples include gravel and rock dams, with and without impervious materials. In some situations, the channel morphology and substrate composition allowed pumps to be placed in upstream pools without the need for dam construction. In one situation, a partial pump around with no dams was used to minimize flow over the ditch area during an open cut crossing.

The degree of success experienced at many crossings was determined by the ability to seal the watercourse or work in dry conditions. Plate steel dams worked very well when conditions were appropriate. Where no dams were constructed and the watercourses were pumped dry above the crossing and discharged below, excellent results were obtained. Conventional sandbags and 1 m^3 sandbag dams seemed to have worked well although seepage became a problem if not constructed properly.

Inadequate pump capacity can be problematic with the dam and pump crossing technique. There were several examples of insufficient capability, pumps breaking down, and pumps running out of fuel. All three situations can be prevented with better pre-planning. Where subsurface flow is a concern, additional pumping from the trench area is required and two upstream dams may be warranted. Common pump sizes include 3", 4", 6", 10" and 12" pumps. In one instance, the limiting factor was the number of pumps which could fit in the pool upstream of the dam.

Pump discharge locations vary depending upon water quality and the standards for water quality. Bypass water, although usually pumped directly back into the watercourse, was discharged on to the ice downstream of the crossing in one situation. Silty trench water was usually pumped on to shore, either into surrounding vegetation or with sumps, settling ponds or silt fence lined areas. In certain situations, water was discharged into silt bags.

Instream activity at most water crossings where the dam and pump method was used required one day or less. Some took one day to set up and one day to construct the crossings. Other examples required 2.5, 3 and 5 days. In the case of the latter, the job was considered to have been poorly conducted by the government inspector with inadequate dams and pumps as well as a poor choice of discharge location.

Apart from environmental protection measures relating to the pump discharge areas and bank reclamation, special measures included a full contingency plan in case the crossing was not successful, fish salvage from the isolated areas and secondary upstream dams to trap seepage which in turn was pumped out. Silt curtain or filter fabric/hay bales were installed downstream of the flume with limited success at some crossings.

The total suspended sediment targets were not exceeded during construction of one crossing where monitoring was conducted and results are available.

In general, dam and pump crossings appear to be successful. Those crossings where difficulties were encountered, were the result of poor planning. In particular it is important to: construct high quality impermeable dams; calculate streamflows and have on hand enough pumps for at least 150% of the anticipated flow; have spare generators, fuel and pumps onsite; and finally, a contingency plan in case unforeseen problems arise. One environmental inspector that had been involved at numerous crossings where the sump and pump [high volume pump] method (*i.e.,* no dams constructed) had been used successfully, believed the term dam and pump was archaic. He felt that the term led many contractors or government representatives to install dams when their use was not warranted.

Flume Case History Summary

Twenty-eight examples of the flume water crossing method were considered in the case history summary.

The flume method was most commonly used on watercourses less than 10 m in width although examples of 30 m, 100 m and two channels of 200 m are included in the case histories. In most cases the flumes were preconstructed large diameter pipes welded to a flange plate. Many of the crossings had multiple pipes, the largest being 4 x 42" and 1 x 48" flumes welded side by side with a single flanged plate on the upstream side. At many crossings where the flume method was used, supplemental pumping was required to handle the flows. In one case the flume method was used in a partial temporary diversion. A channel on one side of an island was flumed and then the other.

Most flumes were sealed by conventional sandbags with an impermeable liner, although dams constructed of 1 m^3 sandbags filled with sand or gravel, dirt, land fill and clay were also used. In one case aquadams were used to dam and direct flow toward the flume while at another crossing, median barriers served to direct a portion of the streamflow into an old stream channel, thereby reducing the flow through the flume.

Most flume crossings require some degree of pumping to minimize or remove the water in the isolated area. In a number cases, several pumps were required to handle the groundwater flow despite a good seal on the dams.

There were several examples of the flumes being installed prior to the crossing construction to allow vehicle access or to avoid instream timing restrictions.

Instream activity at flumed water crossings ranged from four hours for a 2 m wide drainage to eight days for a large river. However, most smaller crossings were completed in three days or less.

Apart from the environmental protection measures relating to pump discharge, fish salvage between the dams and bank reclamation, no special measures were usually employed. Silt curtain or filter fabric/hay bale dams were installed downstream of the flume at some crossings.

Water quality and sedimentation monitoring was conducted at several crossings where the flume method was used with limited success. In one case the short-term total suspended targets were met but the 48 hour targets were surpassed. This crossing was also the largest flume project, encountered problems with unfiltered discharge water re-entering the watercourse and required eight days of instream activity.

The success rate of the flumed crossings indicates that it may not be the best choice for an isolated technique unless conditions are ideal. Problems that created poor, difficult or disastrous crossings included: poor planning; lack of experience; a sinuous stream channel; an unstable ditch and flume which was too short to allow for a wide ditch; poor seals on dams; undersized equipment; organic banks and substrates; insufficient pump discharge area or sump; high groundwater seepage; improperly installed sandbag dams; difficulty threading pipe bends under the flume; steep approach slopes that prevented threading pipe under flume; insufficient flume capacity; pump failure; and leaking hoses.

In general, the degree of success at watercourses crossed using the flume method seems to be less than other crossing techniques. As one construction superintendent confessed, "he has done about a dozen, was only proud of one..."

Temporary Diversion Case History Summary

Seven examples of watercourses crossed using the temporary diversion method were considered in the case history summary. All but two of the examples were on large rivers where alternative techniques to limit sedimentation of downstream areas were limited. Two of the examples required excavation of new channels in old high water or abandoned channels, one had an entirely new channel excavated between meanders in a silty floodplain, and the other four were diversions around islands and gravel bars using existing active channels.

Of those crossings which required excavation of a new channel, one was a last minute decision with no planning and no erosion protection of the new channel. The other two were well planned and had sufficient geotextile and riprap onsite to prevent erosion of the new channel. Those crossings that used existing channels only had erosional concerns as a result of increased water velocity and depth. One example indicated that gravel displacement from a change in flow patterns was noted 900 m downstream of the diversion. At one crossing, flumes were installed to allow flow in the new channel to cross over the previously excavated trench. Flumes were also installed at one crossing as a contingency in the new channel.

The diversion techniques ranged from damming the old channel with soil from the hard plug on the upstream end of the new channel, to imported sandbags and liner, aquadams and median barriers, as well as instream cobbles and material from the gravel bars. Aquadams were used on three of the seven projects although they required reinforcing with median barriers on one large diversion where the aquadams kept washing away. In one instance, a second dam was installed immediately downstream of a sandbag and liner headwall dam to collect seepage which was subsequently flumed over the excavation.

The isolated area was pumped into abandoned channels in two cases although, in one of the instances, large volumes of discharge water resulted in water flowing out of the abandoned channel into the watercourse. Silt fences were erected in the old channel to filter the sediment.

The periods of instream construction when the temporary diversion method was used varied according to the size of the watercourse. The two smallest crossings resulted in two and four days of instream activity. Instream periods of 5 and 17 days were reported for the other two crossings where an instream period was indicated.

Of the three crossings where sedimentation and water quality observations were provided, results indicated that: water quality objectives were met; turbidity was not noticeable while constructing the dams; and only a minimal increase in silt load occurred due to heavy silt load already present in the river. On one crossing it was observed that sedimentation increased after diverting streamflow into an unlined new channel.

Special environmental measures undertaken include: special protection for banks and spoil piles to accommodate increased flow after the diversion into one channel; fish salvage from the isolated channel; and in one instance retaining eagle watchers to let the blasting crew know when eagles had left the area so blasting could proceed.

Generally the temporary diversions, if planned and implemented appropriately, were considered successful. The one crossing where difficulty was encountered was the result of a sudden change in methodology from the open cut trenching method to temporary diversion. Therefore, thorough planning of the procedure and appropriate protection measures were not in place. Difficulties that arose during construction of the crossings considered to be successful were problems associated with the efficient diversion of water; the erosion of the new channels; and the correct placement of spoil so as to avoid susceptibility to erosion caused by increased volumes.

Two-Stage Coffer Dam Case History Study

Five examples of two-stage coffer dams are summarized, although one reference is a generic reference to approximately 40 coffer dam crossings which were undertaken over a several year period and another is similar to five other crossings undertaken by the same construction superintendent.

All examples were constructed within large rivers between 25 m and 100 m in width, with substrates of coarse textured materials. Dams were constructed from various materials including clean pitrun, 1 m^3 sandbags, washed gravel with plastic liner and conventional sandbags. At one crossing where 1 m^3 sandbags were installed, an upstream deflection dam was also constructed to reduce the water velocity in the vicinity of the dam construction. Seepage and infiltration of water into the coffered area posed a problem in all cases. This was generally handled by installing numerous pumps. In one case, a sheet piling dam was installed inside the coffer and sealed with sand. Unfortunately, trench sloughing caused the sheet piling to fall into the trench and cables were installed to hold the sheet piling back. Riprap was installed at one watercourse on the upstream face of the coffer to prevent erosion. Dewatering was either onto the banks or into settling ponds within the coffers. In one example, where silty water from inside the dam was percolating out into the river, a deflection dam was constructed to increase the water pressure on the downstream face of the dam. This prevented any outflow of turbid water by allowing water to infiltrate the coffer. The water was then pumped into a discharge area on the bank.

Instream activity ranged from one week to 72 days. The instream period of 72 days appears to be the exception due to problems encountered during excavation. The other two crossings completed took two and three weeks. One crossing was aborted and open cut in a week after flooding and dam failure endangered the crews.

Special environmental measures employed included downstream silt monitoring, and the installation of sorbent booms in the even of an accidental spill.

Downstream siltation in most cases seems to have been reduced by installation of the coffers although the increased instream period produces a longer duration of silt loading.

In general, coffer dams seem to work well as long as they are well planned and installed by an experienced crew. The engineering manager of the company which had completed 40 coffer dam crossings indicated that once the crew was experienced, construction was very successful. One superintendent also indicated great success once the system had been worked out but also indicated it was very costly and did increase the instream period. The expense was confirmed by one quote of $300,000 for a 100 m crossing. Many of those interviewed during the case history review indicated that they did not have any experience with this crossing method and noted strong reservations related to the mid stream tie-in due to safety and constructability. Two respondents indicated that they would only consider this technique in the event that instream repairs were required.

Horizontal Directional Drilling

Directional drilling can be an effective method for installing pipelines beneath watercourses with relatively low environmental impact to streambanks and water quality. Potential impacts associated with directionally drilled installations include land clearing affecting visual and wildlife values, possible loss of drill mud and the effect on water quality during construction as well as disposal of used drilling mud. The feasibility of using directional drilling techniques is strongly limited by site conditions, including soil characteristics, and available workspace and geometric constraints. The case history review indicated that drill mud seepage can occur for all soil types and is most likely when highly permeable zones are present with minimal cover between the drill path and the bed of the watercourse. There was a higher incidence of drill mud seepage for sites characterized by larger grain sized materials (gravels, cobbles and boulders) than for sites characterized by fine-grained and consolidated materials. The incidence of significant technical difficulty (*i.e.*, loss of equipment, collapsed bore holes and damaged pipes) was higher for sites characterized by the presence of large gravels, cobbles and/or boulders. The feasibility of directionally drilled pipe installations generally decreases for larger diameter pipes and is further compounded when suboptimal soil characteristics are present. There were relatively few large diameter pipe installations in all regions examined in this study.

The significance of potential drill mud seepage into the watercourse is typically limited to point sources along the drill path. In some instances there is the opportunity to reduce or arrest seepage by decreasing the pressure of the drill mud. Depending on where these point sources occur, it may also be possible to implement mitigative measures such as containment berms and vacuum trucks to control water contamination. These measures can be effective for mud seepage occurring along the approach slopes and in some cases, shallow near-shore areas. Significant leakage of drilling mud can also occur at the drill entry or exit point due to different pressure heads if there is a large change in elevation between the two points as well as during reaming or pull-back.

Drill mud seepage was reported for 36 of the 146 cases reviewed. The reported incidence of drill mud seepage was 8% for Alberta and Saskatchewan and 20% for the continental U.S. The incidence of drill mud seepage was 43% for the 37 case histories reviewed in British Columbia. Drill mud seepage occurred at all five crossing reviewed for Ontario and Québec. Drill mud seepage occurred in all soil types including fine- and coarse-grained unconsolidated materials and hard rock. The incidence of drill mud seepage was less than 14% for both the small and medium diameter pipe size categories. Drill mud seepage was reported for 85% of the large diameter pipe installations.

There are a number of site-specific engineering and geological constraints that may preclude the use of drilling as a viable crossing alternative. These include available workspace, pipeline specifications (length and diameter), site geometrics and soil conditions. The technology is particularly well suited for sites with fine-grained soil characteristics (sands, silts and clay and consolidated soil types such as rock and sandstone. Unconsolidated materials with large gravels, cobbles and boulders are extremely difficult to drill and are one of the main limitations to directional drill applications. Potential problems with these materials include deflection of the drill bit, drill bit damage and equipment losses, removing boulders/cobbles from the bore, possible collapse of the bore hole and pipe damage during the pull-back operation. The potential for these problems generally increases with the size of the bore. Although directional drilled installations have been completed through mixtures of gravel, cobble and/or boulders, the installation failure rate and incidence of serious technical difficulties is high. This was particularly true for sites where large cobble and boulders were present. The number of successful installations through these conditions was relatively low. These potential problems are further compounded for installations of large diameter pipes and increased crossing width. The small number of installations involving large diameter pipe identified in this review, coupled with the relatively high incidence of technical difficulty experienced further supports this conclusion.

Significant technical difficulties were reported for 8 of the 37 case histories reviewed for British Columbia. These difficulties included loss of the borehole, pipe damage during the pull-back operation, equipment losses through jamming or breakage, and inaccurate steering control. Three of these incidents required a second bore hole to be drilled before the crossing could be completed. Soil conditions were gravels and cobbles at two of these crossings and shale/rock at the third crossing site. Two other drilled crossings were unsuccessful and were abandoned in favour of alternative crossing methods.

Pipeline Abandonment

A Discussion Paper on
Technical and Environmental Issues

Prepared for the Pipeline Abandonment Steering Committee (comprised of representatives from the Canadian Association of Petroleum Producers, the Canadian Energy Pipeline Association, the Alberta Energy and Utilities Board, and the National Energy Board)

November 1996

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Executive Summary

The Canadian oil and gas industry and federal and provincial regulatory authorities recognize the need to develop guidelines that companies can follow in order to abandon oil and gas pipelines in an environmentally sound, safe, and economical manner. To meet this objective, the Canadian Association of Petroleum Producers and the Canadian Energy Pipeline Association (through their industry participants) have participated along with the National Energy Board and various departments of the Government of Alberta in the development of this discussion paper.

This paper reviews the technical and environmental issues associated with pipeline abandonment and is intended to provide a basis for further discussion on the issue. In order to complete the assessment of this issue, a review of the legal and financial aspects of pipeline abandonment need to be undertaken. More particularly, the core issues of long-term liability and funding need to be addressed both in the context of orphaned pipelines and those with an identifiable owner/operator.

This paper is intended to assist a company in the development of an abandonment plan through the recognition of the general issues which result from the abandonment of a pipeline and by providing the means to address those issues. Land use management, ground subsidence, soil and groundwater contamination, erosion, and the potential to create water conduits are among the topics addressed.

Some follow-up may be required in respect of the technical analysis presented on the issue of ground subsidence. It is suggested that tolerance criteria be developed and that the industry survey referred to in the paper be complemented with a field investigation program. Scale modelling could also be performed to confirm the theoretical ground subsidence calculations.

As illustrated by the diagram on the following page, the pipeline abandonment planning process is a multi-dimensional exercise that requires wide stakeholder input. The abandonment project schedule should also provide an opportunity for meaningful input into the planning process by the affected public, as defined by the scope of the project. It is especially important that landowners and land managers have a central role in this process.

In practice, the decision to abandon in place or through removal should be made on the basis of a comprehensive site-specific assessment. In this context, the analysis presented in this paper has limitations in that all site specifics could not possibly be addressed, particularly in relation to potential environmental impacts or impacts on land use.

The development and implementation of a pipeline abandonment plan that will both minimize impacts to the environment and land use and be cost-effective requires many activities similar in scope to the planning or installation of a new pipeline. For any large-scale abandonment project, it is unlikely that any one abandonment technique will be employed. Rather, a project will usually involve a combination of pipe removal and abandonment-in-place along the length of the pipeline. A key factor influencing the choice between the two options is present and future land use.

In summary, the key features of a proper abandonment plan are (i) that it be tailored to the specifics of the project, (ii) that an early and open opportunity be provided for public and landowner input, and (iii) that it comply with current regulatory requirements. It is also necessary that the plan be broad in scope and encompass post-abandonment responsibilities in the form of right-of-way monitoring and remediation of problems associated with the abandonment.

A major issue still to be addressed is the question of who would assume responsibility if the owner/operator becomes insolvent. In this regard, industry has established a fund in Alberta to cover the cost of reclamation and abandonment of orphaned oil and gas wells and certain associated pipeline facilities.

Committee Representative Lists

Steering Committee

Bob Hill (Chair)	Canadian Energy Pipeline Association
Jim Dilay	Alberta Energy and Utilities Board
Ken Sharp	Alberta Energy and Utilities Board
Ian Scott (Secretary)	Canadian Association of Petroleum Producers
John McCarthy	National Energy Board
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Adolf Bruneski	Alberta Environmental Protection
Paul Vasseur	Alberta Agriculture, Food and Rural Development
Jim Anderson	(Farmers Advocate)
Fred Kuipers	National Energy Board
	Pembina Corporation

Abbreviations

AEP	Alberta Environmental Protection
C&R	Conservation and Reclamation
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
EPEA	*Environmental Protection and Enhancement Act* (Alberta)
EUB	Alberta Energy and Utilities Board (formerly the Alberta Energy Resources Conservation Board)
H_2S	hydrogen sulphide
km	kilometre
mm	millimetre
NEB	National Energy Board
O.D.	outside diameter
PCB	polychlorinated biphenyl
ROW	right-of-way

Glossary of Terms

Abandonment	Refers to the permanent removal from service of the pipeline. A section of pipeline can be abandoned in place or removed. In the former case, it is assumed that cathodic protection of the pipeline is discontinued and that no other measures are taken to maintain the structural integrity of the abandoned pipeline (other than the potential use of solid fill material at roadway and railway crossing sites or other locations sensitive to ground subsidence).
Associated Apparatus	All apparatus associated with a pipeline system, both above and below the ground surface, including pipeline risers, valve assemblies, signage, pig traps, culverts, tanks, and sumps.
Cathodic Protection	A technique to prevent the corrosion of a metal surface by making the surface the cathode of an electrochemical cell.
Corrosion	The deterioration of metal as a result of an electrochemical reaction with its environment.
Deactivation	Refers to the temporary removal from service of the pipeline. In the context of this paper, it is assumed that corrosion control measures are maintained.
Decontamination	The removal or neutralization of chemical substances or hazardous material from a facility or site to prevent, minimize, or mitigate any

	current or future adverse environmental effects.
Decommissioning	One of the steps of pipeline abandonment, generally involving the physical removal of all above-ground appurtenances.
Discontinued	See "deactivation".
Erosion	The process of wearing away the earth's surface through the action of wind and water.
Groundwater	All water under the surface of the ground.
Land Surface Reclamation	The stabilization, contouring, maintenance, conditioning, or reconstruction of the surface of the land to a state that permanently renders the land with a capability that existed just prior to the commencement of abandonment activities, and as close as circumstances permit to that which existed prior to pipeline installation.
Negative Salvage	The net cost of abandoning a pipeline through removal, calculated as the cost of removal less salvage revenue generated from the sale of the removed material for scrap or use by others.
Orphaned	Pipelines and associated facilities for which the licensee and successors are insolvent or non-existent.
Owner/Operator	The individual, partnership, corporation, public agency, or other entity that owns and/or operates the pipeline system.
Pipe Cleaning	The removal of all substances (solid, liquid, or gaseous) and build-ups within the pipeline to a pre-determined level.
Pipeline	All metallic onshore pipelines within the scope of the CSA Z662-94 "Oil and Gas Pipeline Systems" standard, including associated appurtenances such as valve assemblies, drip pots, cathodic protection beds, signage, and headers, but not including station facilities such as pump or compressor stations.
Pipeline System	The combination of pipelines, stations, and other facilities required for the measurement, processing, storage, and transportation of oil, gas, or other hydrocarbon fluid.
Reclamation	Any one of the following: • the removal of equipment or buildings or other structures or appurtenances; • the conducting of investigations to determine the presence of substances; • the decontamination of buildings or other structures or other appurtenances, or land or water; • the stabilization, contouring, maintenance conditioning, or reconstruction of the land surface; or • any other procedure, operation, or requirement specified in the regulations. (as defined in the Alberta *Environmental Protection and Enhancement Act*)
Removal	The pipeline is completely removed from the right-of-way.
Roach	Excess soil placed over the ditch line to compensate for soil settlement.
Road or Railway Crossing	The crossing by a pipeline of a highway, road, street, or railway.
Sight Block	A mechanism to restrict the visual impact of a pipeline right-of-way.

Soil	The naturally occurring, unconsolidated mineral or organic material at least 10 centimetres thick that occurs at the earth's surface and is capable of supporting plants. It includes disturbance of the surface by human activities such as cultivation and logging but not displaced materials such as mine spoils.
Spoil	Soil materials other than topsoil excavated from the trench. In most cases, the excavated soil is suitable for return to the pipeline trench, and allows for re-contouring of the right-of-way.
Subsoil	Although a common term it cannot be defined accurately. It may be the B horizon of a soil with a distinct profile. It can also be defined as the zone below the plowed soil in which roots normally grow.
Surface Water	Water in a watercourse and water at a depth of not more than 15 metres beneath the surface of the ground.
Suspension	The cessation of normal operation of a pipeline pursuant to its licensed use. The pipeline need not be rendered permanently incapable of its licensed use, but must be left in a safe and stable state during this period of suspension, as prescribed by the applicable regulations and guidelines. See also "deactivation".
Topsoil	The organo-mineral suface "A", organic surface "O" horizon, or dark coloured surface soil materials, used synonymously with first lift. First lift materials are usually removed to the depth of the first easily identified colour change, or to specified depth where colour change is poor, and contain the soil Ah, Ap, O, or Ahe horizon. Other horizons may be included in the first lift if necessary.
Water	All water on or under the surface of the ground.
Water Conduit	A channel for conveying water. In the context of pipeline abandonment, refers to a pipeline that has become corroded and perforated and transports ground or surface water to a different location.
Watercourse	(i) The bed and shore of a river, stream, lake, creek, lagoon, swamp, marsh, or other natural body of water; or (ii) a canal, ditch, reservoir, or other man-made surface feature, whether it contains or conveys water continuously or intermittently.

Section 1

Introduction

1.1 Background

Approximately 540,000 km of operating oil and gas pipelines currently exist in Canada, about 50 percent of which are located in Alberta. Ultimately, all oil and gas pipelines will reach the end of their useful lives, and will be abandoned. The issue of pipeline abandonment should therefore be reviewed by all stakeholders.

The Alberta Energy and Utilities Board (EUB) estimates that about 17,000 km of pipeline were abandoned or discontinued in Alberta as of April 1994. This number includes an estimated 3,600 km of orphaned abandoned pipelines. The majority of abandoned pipelines in Alberta are gathering lines 168.3 mm or less in outside diameter.

Regulatory requirements for pipeline abandonment vary across jurisdictions in Canada, and in many cases do not completely address associated long-term issues.

1.2 Review Initiatives

In 1984, several parties at a National Energy Board (NEB) hearing into the tolls of a major natural gas transmission pipeline company showed an interest in addressing the issue of negative salvage as it related to pipeline abandonment. As a result, the NEB issued a background paper in September 1985 addressing the negative salvage impacts of pipeline abandonment. The issue was not pursued again until 1990, when industry, the Alberta Energy Resources Conservation Board (now the EUB), and Alberta Environmental Protection (AEP) discussed the issue of pipeline abandonment while considering amendments to the pipeline regulations issued pursuant to the *Pipeline Act* (Revised Statutes of Alberta 1980). The issue was not resolved at that time, and was again raised in 1993 by the Alberta Pipeline Environmental Steering Committee, an industry, government, and public stakeholder group established to address pipeline related issues.

In October 1993, the Canadian Association of Petroleum Producers (CAPP) received the endorsement of the Alberta Petroleum Industry Government Environment Committee to establish a steering committee to oversee the issue of pipeline abandonment. Shortly thereafter, the EUB requested that CAPP and the Canadian Energy Pipeline Association (CEPA) organize a steering committee to resolve the concerns surrounding abandonment.

In April 1994, representatives from CAPP, CEPA, the EUB, and the NEB met to establish a pipeline abandonment steering committee. It was also decided at that time that separate subcommittees be struck to address the technical, environmental, legal, and financial aspects of pipeline abandonment. The technical and environmental subcommittees were the first to be formed and, together with the steering committee, were responsible for this discussion paper. The legal and financial subcommittees have not yet been struck.

1.3 Scope

This discussion paper is intended to apply to all buried metallic pipeline facilities falling within the scope of the CSA Z662-94 "Oil and Gas Pipeline Systems" standard, except for offshore pipelines. Many of the same issues and concepts (such as those relating to land use and pipe cleanliness) also apply to plastic and fibreglass pipelines. It addresses pipeline abandonment only (i.e. permanent removal from service), and does not consider pipeline deactivation (i.e. temporary removal from service). Likewise, this document does not address the abandonment of aboveground facilities associated with pipelines, such as stations or tank farms, or specific facilities such as underground vaults.

This paper addresses the technical and environmental aspects of pipeline abandonment. In order to complete the assessment, a review of the legal and financial aspects of pipeline abandonment needs to be undertaken. More particularly, the core issues of long-term liability and funding need to be addressed both in the context of orphaned pipelines and those with an identifiable owner/operator.

1.4 Abandonment Options

The two basic options that are considered in this paper are (i) abandonment-in-place and (ii) pipeline removal. In the former case, it is assumed for the purposes of this paper that cathodic protection of the pipeline is discontinued and that no other measures are taken to maintain the structural integrity of the abandoned pipeline (other than the potential use of solid fill material at roadway and railway crossing sites or other locations highly sensitive to ground subsidence).

As noted in Section 2, for any large-scale abandonment project it is unlikely that only one of these options will be employed. Rather, a project will usually involve a combination of pipe removal and abandonment-in-place along the length of the pipeline. A key factor influencing the choice between the two options is present and future land use.

It is further noted that the abandonment techniques presented are confined to those possible using currently available technology. While developments in pipeline removal and abandonment technologies were evaluated, no major improvements to the methods currently in use were discovered. However, as pipeline abandonments become more prevalent, improved abandonment methods will likely be developed.

1.5 Objective

The objective of this discussion paper is to assist the user in the development of a pipeline abandonment plan, a framework for which is provided in Section 2 of this paper. More particularly, the paper is meant to assist parties in making an informed decision between abandoning in place or through removal. Section 3 outlines the general technical and environmental issues that should be considered when abandoning a pipeline, while Section 4 elaborates on post-abandonment responsibilities. Site-specific issues should be addressed on a case-by-case basis.

The objective of creating an abandonment plan is to ensure that identified issues have been addressed and that the pipeline is abandoned in a way that provides a forum for meaningful stakeholder input and ensures that public safety and environmental stability are maintained.

1.6 Regulatory Requirements

The NEB is responsible for regulating interprovincial and international pipeline systems in Canada, while the individual provinces are responsible for regulating intraprovincial pipeline systems. Within each province, gathering, transmission, and distribution pipelines may be regulated by different agencies. For example, in Alberta the EUB regulates gathering and transmission lines as well as higher-pressure distribution lines (greater than 700 kPa), while lower-pressure distribution lines are regulated by Alberta Transportation and Utilities. AEP, through the *Environmental Protection and Enhancement Act* (EPEA), regulates conservation and reclamation activities for all three categories of pipelines.

In addition to the primary regulators, there may be other governmental agencies within each of the respective jurisdictions that may have an interest in the abandonment and reclamation of a pipeline. These other agencies may include local governments, especially in populated areas where pipeline abandonment may impact upon land uses.

In Alberta, the EUB sets the requirements for the abandonment of gathering and transmission lines. In addition to meeting the EUB's abandonment requirements, the pipeline right-of-way must be reclaimed to AEP standards. Reclamation certificates are issued by inspectors designated under EPEA. For removal projects that are classified as Class I projects,[1] the operator is required to obtain an approval under EPEA from AEP to ensure that proper conservation and reclamation occurs. For smaller projects, AEP's *Environmental Protection Guidelines for Pipelines* are to be followed during construction.

For federally regulated pipelines, approval to abandon a pipeline must be granted by the NEB and pipelines must be abandoned in accordance with the requirements of the NEB's *Onshore*

Pipeline Regulations. These regulations are in the process of being revised, and future regulations will likely require that applications for pipeline abandonment be treated on a case-by-case basis.

A summary of the current regulatory requirements for pipeline abandonment across Canada has been included as Appendix A.

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[1] *A Class I pipeline is defined by the Activities Designation Regulation (AR 110/93) under EPEA as any pipeline that has an index of 2690 or greater, determined by mutiplying the diameter of the pipeline in millimetres by the length of the pipeline in kilometres (e.g. 168.3 mm x 16 km = 2693).*

Section 2

Developing an Abandonment Plan

This paper addresses the common issues that pipeline abandonment plans should address regardless of regulatory jurisdiction. It is intended to assist a company in the development of an abandonment plan through the recognition of the general issues which result from the abandonment of a pipeline and by providing the means to address those issues.

In practice, the decision to abandon in place or through removal should be made on the basis of a comprehensive site-specific assessment. In this context, the analysis presented in this paper has limitations in that all site specifics could not possibly be addressed, particularly in relation to potential environmental impacts or impacts on present and future land use.

The development and implementation of a pipeline abandonment plan that will minimize impacts to the environment and land use and be cost-effective requires many activities similar in scope to the planning or installation of a new pipeline. For any large-scale abandonment project, it is unlikely that any one abandonment technique will be employed. Once the principal technique has been chosen, therefore, the owner/operator should assess on a site-specific basis whether an alternate approach should be followed for selected segments of line.

The abandonment project schedule should provide an opportunity for meaningful input into the planning process by the affected public, as defined by the scope of the project. It is especially important that landowners and land managers have a central role in this process.

The development of an abandonment plan should be initiated by reviewing the general requirements of the regulatory jurisdiction(s) under which the pipeline is operated. Beyond the requirements of the principal regulatory agencies, other legislation may affect the particular abandonment project. For example, municipal requirements and federal legislation such as the federal *Navigable Waters Protection Act* or the *Fisheries Act* may affect the abandonment options.

It is also critical that easement agreements be reviewed, as their terms and conditions may bear on the abandonment decision-making process.

The development and implementation of an abandonment plan consists of at least the following seven steps:

(1) review prevailing regulatory requirements applicable to the abandonment project;

(2) compile all relevant information on the pipeline system, including easement agreements;

(3) analyze by segment taking into account the factors addressed in Section 3 of this paper, including present and future land use;

(4) develop the abandonment plan in consultation with stakeholders (such as landowners, government authorities, and other directly affected parties), incorporating the information compiled in the above steps;

(5) secure regulatory and landowner approvals as required for the pipeline abandonment and site reclamation;

(6) implement the abandonment plan, the scope of which should include post-abandonment responsibilities (addressed in Section 4); and

(7) secure final regulatory release.

A proponent undertaking an abandonment plan should follow these six steps, recognizing that site-specific conditions may require additional steps in the development of the plan.

Please refer to the next page for a flowchart of the abandonment planning process and to Appendix B for a detailed abandonment checklist.

Flowchart

Section 3

Technical and Environmental Issues

3.1 Issue Identification

Abandonment issues arise from the need to address public safety, environmental protection, and future land use. An initial scoping exercise was carried out to identify the various technical and environmental issues associated with abandonment. Following the development of a detailed issues list, field studies of existing abandoned facilities were performed to verify the issues. In some cases, detailed studies were commissioned in order to better understand the effects and interactions of certain issues. [2]

The primary issues that were identified, and which are addressed in this section, are as follows:

- land use management;
- ground subsidence;
- soil and groundwater contamination;
- pipe cleanliness;
- water crossings;
- erosion;
- utility and pipeline crossings;
- creation of water conduits;
- associated apparatus; and
- cost of abandonment.

It was determined that most issues are not unique to the abandonment phase of the pipeline life-cycle, but could involve an altered scope, varied timeline, or additional stakeholders when compared to the issues of pipeline installation and operation. In order to responsibly abandon a pipeline, the operator must consider all of the issues and determine how they relate to the specific pipeline under consideration, in addition to addressing stakeholder concerns and incorporating collected input.

In any abandonment project, it is possible that a combination of both the abandonment-in-place and removal options would be used, based on site-specific requirements. Thus, it is important that all aspects of the abandonment issues be considered. As the following discussion illustrates, the abandonmen-in-place option does not eliminate the need for land disturbance or field activity, while pipeline removal need not encompass the same level of disturbance or activity as that of pipeline construction.

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[2] *(Refer to the Bibliography in Appendix E for a list of the studies, copies of which are available for public viewing in the libraries of CAPP, CEPA, the EUB, and the NEB.)*

3.2 Land Use Management

Land use is the most important factor to consider in determining whether a pipeline section should be abandoned in place or removed. Therefore, an understanding of the current and potential land uses along the pipeline right-of-way is essential to making informed decisions on available abandonment options.

Of particular concern with respect to land use management are areas sensitive to land disturbance, such as native prairie, parks and ecological reserves, unstable or highly erodible slopes, areas susceptible to severe wind erosion, and irrigated land, particularly flood irrigation systems. Additionally, land improvement activities such as the installation of drainage tile or other drainage systems, landscaping, and permanent structure installations could be affected by a proponent's decision to abandon a line.

Future land use should be considered because a pipeline abandoned in place could become a physical obstruction to development, such as excavation for foundations, pilings, or ongoing management practices such as deep ploughing or the installation of sub-drains. It is critical that input be gathered from appropriate sources such as landowners, land managers, lessees, and municipal agencies to support the decision to abandon in place. In addition, sufficient documentation must be kept to allow for detailed location information for future developers or owners.

As noted in Section 2, the decision to abandon in place or through removal should be made on the basis of a comprehensive site-specific assessment. In this context, the land management characteristics that may be better suited to pipeline abandonment-in-place include, but are not limited to:

- parks and natural areas;
- unstable or highly erodible surfaces;
- water crossings;
- flood irrigated fields;
- road and railway crossings; [3]
- foreign pipeline crossings;
- extra depth burial of pipe (i.e. depth well in excess of one metre);
- native prairie and native parkland;
- forest cut blocks;
- designated waterfowl and wildlife habitat; and
- areas exhibiting poor and/or limited access.

The key environmental protection measures to be considered when a pipeline is to be abandoned in place are as follows:

- minimal disruption to ongoing or future land management activities;
- a complete and documented pipeline cleaning procedure;
- the clean-up of any spills or contaminated sites to prevailing regulatory requirements;
- a revegetation strategy to achieve pre-abandonment conditions, keeping erosion control and soil stability as a priority;
- topsoil conservation for all areas disturbed during the abandonment process;
- reclamation of all site access roads, including those which had been developed for the operational phase of the pipeline and any opened or developed for abandonment activity;
- documented as-built information for future reference;
- application of sight blocks where appropriate (e.g. recreational areas and wildlife habitat); and
- a monitoring program acceptable to all affected parties to ensure a process to complete remediation.

Proper environmental protection measures should be implemented, including appropriate soil handling procedures, timber management, contingency plans (e.g. for spills and wind or water erosion), protection of cultural features, weed control, and site reclamation. For example, in Alberta, a Conservation and Reclamation (C&R) report may be required by AEP for pipelines which were constructed before the C&R regulations came into effect.

Prior to the commencement of field activity, reclamation criteria should be agreed upon by the owner/operator, regulatory authority, and landowner. The reclamation program will normally be designed to ensure that the condition of the right-of-way land surface is made at least equivalent to that existing just prior to the commencement of abandonment activities, and as close as circumstances permit to the condition of the land that existed prior to pipeline installation, and may entail:

- removing, storing, and replacing topsoil;
- soil contamination analysis and-clean up, if required;
- contouring disturbed land to control drainage;
- seeding affected areas to prevent erosion and establish vegetation;
- removal of all structures to a minimum depth of one metre below final contour elevation; 4
- roaching and/or compacting excavated areas to compensate for future settlement; and
- site-specific environmental requirements (e.g. reforestation).

As noted in Section 4, a right-of-way monitoring plan should be developed to ensure that reclamation efforts are successful and that no problems arise.

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[3] *(as detailed in Section 3.8, consideration should be given to filling pipeline sections abandoned in place underneath roadways and railways with a solid material such as concrete in light of potential ground subsidence impacts.)*

[4] *(In areas where circumstances such as special farming practices or nearby urban development exist, consideration should be given to removing structures more than one metre below the final contour elevation.)*

3.3 Ground Subsidence

3.3.1 General

The long term structural deterioration of a pipeline abandoned in place may lead to some measure of ground subsidence. This is a primary issue to consider for larger-diameter pipelines because of potential environmental and safety concerns. More particularly, ground subsidence could create the potential for water channelling and subsequent erosion, lead to topsoil loss, impact on land use and land aesthetics, and/or pose a safety hazard.

The acceptable subsidence limits and the potential factors affecting those limits are significant areas requiring attention in the development of any abandonment plan. Erosion may cause direct siltation to a watercourse, or cause slope failures and subsequent siltation. Where potential siltation is an issue, proponents must be prepared to deal with fisheries protection measures to remain in compliance with provincial and federal legislation.

The rate and amount of ground subsidence over time is difficult to predict as it depends on a complex combination of site-specific factors, such as the corrosion mechanics in the vicinity of the pipeline, the thickness and diameter of the pipeline, the quality of the pipeline's coating, burial depth, soil type, the failure mechanics of the pipeline material, and soil failure mechanics.

Given the absence of previously documented research, studies were commissioned on corrosion and soil mechanics in an attempt to establish the connection between pipeline corrosion, the structural deterioration of pipe, and the resultant ground subsidence that might be observed. Summaries of these studies and the conclusions that were reached follow.

3.3.2 Pipeline Corrosion

The corrosion consultant's report addressed the mechanism of corrosion leading to ultimate structural failure of a pipeline. The report stated that the rate of corrosion of an abandoned pipeline can vary significantly due to the many factors which must be present for corrosion to take place. Corrosion of buried pipelines occurs through an electrochemical reaction that involves the loss of metal in one location (called the anode) through the transfer of the metal ions to another location on the pipeline (called the cathode). The rate of metal transfer depends on a number of factors such as the quality of the pipeline coating, soil aeration (which supplies oxygen to the pipe to allow the corrosion process to occur), types and homogeneity of soils, soil moisture, and electrical factors which create the potential differences for a corrosion cell to be established.

The corrosion of a coated pipeline is normally restricted to those isolated areas where there are defects in the coating or where the coating has become disbonded from the pipe. Corrosion can be expected to be almost negligible in areas where the coating integrity is intact. Based on his experience, the consultant observed that coating holidays or disbondment occur on less than one percent of the length of most pipelines. Pipeline corrosion in most cases occurs as localized pits, or spiral corrosion areas, which eventually result in random perforations throughout the length of the pipeline. It is extremely rare for corrosion to cover large areas of pipeline, rendering a long segment of the pipeline susceptible to sudden and complete structural failure.

To illustrate typical corrosion rates, the consultant used an example of a 323.9 mm O.D. pipeline in soils commonly found throughout Alberta and estimated that penetrating pits would occur in the range of 13 to 123 years. Based upon the slow rate of pitting corrosion that would occur in most cases, complete structural failure is not likely to occur for decades or even centuries. Furthermore, given the non-uniform nature of the corrosion process, it can be concluded that it is highly unlikely that significant lengths of the pipeline would collapse at any one time.

3.3.3 Soil Mechanics

The soil mechanics report indicated that there has been no documented incidence of ground subsidence due to pipeline structural failure. In order to predict soil reaction to pipeline structural failure, the consultant modelled its review on shallow mining and tunnelling research and documented case histories. The focus of the study was to estimate possible surface subsidence that could be attributed to the complete failure of tunnels of equal diameter and depth as the pipelines being modelled. This represented a worst-case scenario, since as noted earlier a complete pipeline collapse of any significant length is considered highly improbable.

The report employed two different theoretical soil modelling techniques, the Rectangular Soil Block and the Active Soil Wedge, to reflect the most common types of soils that may be encountered. The ranges of subsidence calculated for varying sizes of pipelines provided an approximation of the impacts that a significant pipeline collapse would have on soils. The analysis indicated that ground subsidence associated with the collapse of pipelines up to 323.9 mm in diameter at typical burial depths would be negligible. The analysis further indicated that while there would be some degree of subsidence associated with larger pipeline sizes, it may be of sufficiently small scale so as to be in a tolerable range.

3.3.4 Field Investigation Program

In order to validate the conclusions of the technical reports, the subcommittees undertook to document the ground subsidence of known abandoned pipelines.

As a first step, the subcommittees searched the EUB's records and identified pipelines 168.3 mm or larger in diameter that had been abandoned in place. Questionnaires were forwarded to the owners/operators of some of those lines, requesting information on pipeline diameter, coating type, year abandoned, whether cathodic protection had been removed, and ground subsidence observations (reference Appendix C for copy of questionnaire). The responses to the survey, as well as industry discussions, did not reveal any instances of observed subsidence.[5]

(As indicated in Appendix C, all of the survey results gathered by the subcommittees are available for public viewing in the libraries of CAPP, CEPA, the EUB, and the NEB.)

3.3.5 Summary of Findings

The analyses indicated that the structural failure of an abandoned pipeline due to corrosion may take many decades, and that significant lengths of the pipeline would not collapse at any one time due to the localized nature of the pitting process. Furthermore, the analyses indicated that, even if the worst-case scenario of uniform and total structural collapse was realized, ground subsidence would be negligible for pipelines up to 323.9 mm in diameter.

The degree of subsidence associated with larger-diameter pipelines is highly dependent on pipeline diameter, depth of cover, and local soil conditions, but can be expected in many cases to be in a tolerable range. It should be noted that tolerance to soil subsidence is in itself a site-specific issue, as it depends on land use and the local environmental setting. Any pipeline owner/operator considering the abandonment-in-place of a larger-diameter pipeline should therefore conduct a site-specific analysis in order to evaluate both the degree and tolerability of any long-term subsidence that might be expected. Such analyses should take into account the potential for heavy vehicular loadings (e.g. farm equipment or logging trucks).

On the basis of the foregoing, it is suggested that ground subsidence associated with the structural failure of pipelines abandoned in place will not usually be a critical issue. This conclusion was corroborated by the industry survey referred to in Section 3.3.4. In areas where no settlement is allowed, either by regulation or agreement (such as at highway crossing sites, as further explained in Section 3.8), the option would exist to fill the pipeline with an approved solid material such as concrete or sand.

In terms of follow-up on this issue, it is suggested that tolerance criteria be developed and that the industry survey referred to in this paper be complemented with a field observation program. Scale modelling could also be performed to confirm the theoretical ground subsidence calculations.

3.3.6 Subsidence as a Result of Pipeline Removal

The physical act of removing a pipeline is essentially the reverse operation of pipeline construction and involves topsoil removal, backhoe excavation of the subsoil to a depth at least even with the top of the pipe, pipe removal, backfilling and compaction of the trench, replacement of the topsoil, and revegetation measures.

During pipeline construction, a roach consisting of subsoil overlaid with topsoil is usually employed to compensate for the settlement that will occur as the ditch line settles. The same strategy can be employed at the abandonment stage to avoid the need for reclamation in future years due to settlement and erosion. In general, if extra topsoil or soil materials are required for this operation, it could be recovered from areas immediately adjacent to the pipeline right-of-way. For older pipelines built before mandatory soil conservation, this is where extra topsoil or soil materials may have been disposed. Further surveys or examinations of topsoil depths and soil volumes may be required to identify these potential borrow areas.

Without the concern of compaction damaging the pipeline, a company may undertake a more rigorous compaction of the soil being replaced in the ditch following pipe removal than after backfilling for new construction. Additional compaction may also result in less topsoil handling and, therefore, fewer impacts due to the decreased need to strip topsoil to accommodate the feathering out of subsoil material caused by the excavation.

3.4 Soil and Groundwater Contamination

The abandonment plan should address the potential for contamination associated with the abandonment activities, as well as the need to eliminate any contamination that may already exist, and include the appropriate pipe cleaning or pigging procedure. Any contamination noted prior to abandonment activity should be cleaned up to the applicable regulatory standards prior to full project disturbance, unless it is more economically efficient to include the cleanup in the scope of abandonment activity and it can be demonstrated that environmental damage will not be amplified.

In order to gain additional insight into the issue of contamination, a study was commissioned into the types and quantities of contaminants that might be released from pipelines abandoned in place.

The potential sources of contamination were identified as:

- the substances produced from the reservoir in the hydrocarbon stream and deposited on the walls of the pipeline;
- treatment chemicals which could enter the pipeline and be deposited;
- the line pipe and associated facilities;
- pipeline coatings and their degradation products;
- historical leaks and spills of product that were not cleaned to current standards; and
- possible PCB contamination, if PCBs were used in the pump or compressor lubricants at some point in the history of the pipeline.

The quantity of residual contaminants can be expected to decrease as the product moves from the wellhead through the gathering, processing, and distribution systems. Traditionally, oil pipelines contain a greater volume of wax and scale than do natural gas pipelines, but this is dependent on the circumstances of the particular production field. The study concluded that the effectiveness of pipeline pigging and cleaning procedures prior to abandonment was the most critical determinant of the potential quantities of residual contaminants.

The subject of pipeline cleaning is addressed at length in Section 3.5 and Appendix D. An operator should become familiar with prevailing regulatory standards for soil and groundwater, as these standards may dictate the minimum acceptable level of pipe cleanliness. Sound environmental protection practices should be observed throughout the pipeline cleaning process, such as the use of properly engineered containment and storage for all collected material, proper labelling, disposal processes conforming to local regulations, and effective spill contingency plans. Detailed documentation should be recorded on the results of the cleaning process or the clean-up of a contaminated site.

Operators should also have an understanding of the composition of pipe coatings and their associated characteristics to assess any potential risk that may be derived from abandoning the pipeline in place. For example, pipeline coatings containing asbestos should be handled through special means by trained personnel. It has been suggested that if pipe coating compounds would be accepted at local landfills, then abandoning a pipeline with the same compounds in place may not be a concern, depending on site conditions and concentration levels. Presently, limited information exists regarding the long-term decomposition of pipeline coatings. However, it can be assumed that as the coating adhesive degrades, or is consumed by soil organisms, coatings will eventually disbond and contribute to the corrosion process.

Many of the same contamination prevention measures to be employed for abandonment-in-place also come into play in the context of pipeline removal. Of prime importance is the need to clean the pipeline to accepted standards prior to the commencement of the removal operation, and the employment of measures to prevent spills of the substances collected as a result of the cleaning process. Collection trays should be used during the pipe cutting operation to catch any residual fluids.

During pipe removal, proper soil handling measures must be implemented to ensure topsoil conservation.

In addition to the pipeline itself, the dismantlement of any connected facilities should be carried out such that the potential for contamination is controlled by proper containment and storage for disposal at an approved facility.

3.5 Pipe Cleanliness

3.5.1 Cleanliness Criteria

In light of potential contamination concerns, the cleanliness of the pipeline is an issue for both abandonment techniques. Although responsible cleaning procedures have been defined and are discussed in detail in Section 3.5.2 and Appendix D, the question of "how clean is clean" has not been resolved. In addition, the question remains as to whether pipe that will be removed should be subject to the same cleanliness criteria as pipe that will be left in place. It should be assumed that pipe that is to be removed should be cleaned to a level where any remaining residues will not cause harm in any future intended use of the pipe. Removed pipe that may eventually be put to some alternative use (e.g. pilings) may require more study to determine the appropriate cleanliness requirements for the future use. For pipe that is targeted for disposal, existing disposal or landfilling guidelines will determine the required cleanliness of the pipe.

For pipe that will be abandoned in place, the issue of pipe cleanliness is related to corrosion and the creation of water conduits. Eventually the pipe will corrode until perforated and, aided by the destructive forces of the freeze-thawing of infiltrated water, the structural integrity of the pipe will suffer. Whether the rate of deterioration will be greater than the life of the contaminants left as internal residue of the pipe is unclear. Similarly, an issue remains over the rate and structural location of any corrosion, in that it may allow water to infiltrate the abandoned pipe and transport pipe residues to some other exit point.

3.5.2 Cleaning Procedures

The pigging procedure used during the final operating stages and during evacuation of the pipeline is critical in preparing the line for abandonment. The study on contaminants concluded that the small quantities of hydrocarbons left in the line after a concerted pig cleaning effort will not result in any significant environmental concerns.

The factors impacting the effectiveness of any pig cleaning procedure will vary with each pipeline. Cleaning programs must therefore be customized to the specific circumstances of the pipeline under consideration for abandonment. For guidance purposes, Appendix D sets out general cleaning considerations and describes typical cleaning methods for an oil pipeline in a medium duty service [6] or for a pipeline carrying relatively dry natural gas. Operators planning a pigging program for a specific line should consider these guidelines as a starting point only. The abandonment of pipelines carrying products other than the two noted above require customized pigging procedures to ensure proper cleaning. Care should be taken in all cases to properly contain and dispose of pigged effluent.

A pipeline to be abandoned in place should be left such that no solids or waxy build-up are visible at any point along the pipeline as observed through standard pipe openings such as opened flange or sample connections and the contents have been cleaned out to the extent that no more than a thin oily film on the inside pipe wall surface can be detected by feel or sight. Sour liquid or natural gas pipelines should be checked to confirm that H_2S levels are below acceptable limits.

Pipe cleaning is also of critical importance in the context of pipeline removal, given the desire to minimize the risk of soil and groundwater contamination during the removal process and the hazards associated with pipe removal (e.g. health and flammability hazards of exposed vapours). Cleanliness considerations relating to the future intended use or disposal of the pipe should also be taken into account, bearing in mind that supplementary cleaning techniques may be employed once the pipe has been removed from the ground.

Cleaning effectiveness can be determined by taking pipe coupons and swabs of any film found on the inside of the pipe and analyzing them for contamination, using cutout means such as hot tapping or line cutouts.

After allowing some time for the collection of remaining liquids in low areas (minimum one week suggested), the pipeline should be excavated at random low areas. A minimum of one excavation site per scraper trap or 80 km interval is suggested. However, in undulating areas multiple excavation sites may be required. Excavation sites should be chosen to avoid environmentally sensitive areas and to minimize clearing associated with the opening of access roads. If the examination of the inside wall shows that the cleanliness criteria has been met, the cleaning task can be considered complete.

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[6] *Medium duty service refers to relatively wax and direct free operation with a scraping program undertaken occassionally to move along anything collected or adhering to the pipe wall.*

3.6 Water Crossings

The effect of pipelines on water crossings is an important issue at any stage of a pipeline project. This issue is a significant social consideration due to the visibility of crossing activities, the importance of fisheries resources, public use of waterways, the sensitivity of the resource, and the fact that waterways are an important cultural and historical feature of the land.

There are many factors to consider in deciding whether a section of pipeline crossing a water body or wetland (e.g. muskeg, swamp, or flood plains) should be abandoned in place or removed. More specifically, the risks associated with abandoning the pipeline in place, including the potential for contamination and pipe exposure, have to be weighed against the cost and environmental impact of removal.

These trade-offs should be assessed on a site-specific basis, taking into account the size and dynamics of the water body, the design of the pipeline crossing, soil characteristics, slope stability, and environmental sensitivities. While these issues must be evaluated, in most cases it can be expected that abandonment-in-place will be the preferred option.

If the pipeline crossing is to be abandoned in place, the pipe should be left in as clean a state as possible to minimize the potential for contamination of the waterbody should the eventual perforation and failure of the pipe allow any internal residues to escape. As described in Section 3.9, the strategic placement of caps and plugs will also help mitigate this concern by interrupting the movement of potential contaminants through the abandoned pipe.

The risk of pipe exposure is two-fold. First, the pipeline could become exposed if the overlying soil is gradually eroded or washed away because of the dynamics of the water body (e.g. stream bank migration, scour, or flood conditions). Secondly, an empty pipeline crossing a water body or wet area could float toward the surface if buoyancy control mechanisms fail (e.g. if concrete saddle weights slide off). In either case, the owner/operator should assess the probability that the pipeline could become exposed and the impacts that exposure would entail. If the risk of flotation is a concern, it could be addressed by either perforating the line following an appropriately sensitive line cleaning program to allow it to fill with water or by filling the line with concrete or some other solid material. In the case of the former option, plugs and caps should be used to prevent water migration through the pipeline.

If applicable, the risks associated with abandoning a pipeline in place which runs parallel to an operating pipeline at a water crossing should also be assessed.

If the pipeline is to be removed in whole or in part, the issues would be similar in many ways to those associated with initial construction across the water body or wetland. More specifically, many of the same construction techniques and environmental protection measures would apply. Aspects to address include fisheries resource timing sensitivities, habitat protection, sediment control, vehicle and equipment crossing methods, backfill material specifications and source, erosion control measures (both short term and long term), and bank restoration. Damage to any existing bank stabilization structures or destabilization of previously stable banks should be considered.

It is crucial that the pipe be as clean as possible prior to excavation to minimize the potential for contamination of the waterbody should the pipe be damaged and a spill occur during the removal procedure. Blinding off the ends of the section being removed is recommended to prevent contamination by any remaining traces of material.

3.7 Erosion

Soil erosion is a concern during all phases of the pipeline life-cycle, particularly as it relates to slope stability. Leaving a pipeline in the ground may entail a certain amount of activity along the right-of-way to ensure responsible abandonment, such as excavations to confirm cleaning quality and the installation of caps or plugs. The potential impact of the ensuing right-of-way disturbance will vary greatly with the geographic location of the activity. For example, a forest area "duff" layer may not be as susceptible to erosion and slope instability as a region of native prairie topsoil.

If the pipe is to be removed, erosion and slope stability concerns will be similar to those for pipeline construction. For example, traffic, soil compaction, and the wind and water erosion of disturbed soil may be of concern. In addition, the pipeline may have become a structural support to many slopes over time, and its removal may affect the integrity of the slope.

When developing an abandonment plan, the pipeline owner/operator should review any erosion remediation that had occurred over the operating life of the pipeline. If erosion control measures have been regularly required at specific locations, the owner/operator should determine if it would be appropriate to implement longer term erosion control measures.

If the abandonment activities necessitate disturbing erosion-prone areas including slopes, protection measures designed to current standards should be implemented. In addition, the integrity and effectiveness of any existing ditch plugs, sub-drains, berms, or other installations should be reviewed.

It is usually more appropriate to abandon pipe at unstable slopes in place, due to the potential requirement for extensive remediation if the pipeline is removed. On sensitive slopes, the use of sight blocks or other measures should be considered to discourage use of the right-of-way. In areas where the right-of-way has been traditional access for recreational users or hunters, the operator should attempt to reach an agreement with the land manager for ongoing remediation, if necessary.

In areas where slope movement was being monitored during the pipeline's operating life, the monitoring program should be re-evaluated and continued, if warranted. Temporary access roads to slopes should be reclaimed as appropriate.

Protective measures to be considered when removing a pipeline from a slope would be similar to those used during pipeline construction. The integrity of the slope must be maintained during the removal activities, as well as after the line is removed. If the removal calls for spot excavations (bellholes) instead of an open ditch removal, the stability of the entire slope, as well as the region surrounding the bellholes, should be evaluated. Re-installation of diversion berms and ditch plugs to prevent water channelling may be required.

Development of the abandonment plan should include consultations with other pipeline owners/operators that may be affected by right-of-way disturbances on the slope. In addition, regulators and landowners should be consulted in order to determine an appropriate period for right-of-way monitoring after the pipeline is removed. A typical monitoring period would be two years. Revegetation programs should consider the inclusion of a species that is quick to establish in the revegetation mixture, as this may help to provide short term erosion control; however, the environmental effect of introducing a non-native species must be considered. Regulatory/landowner approval of the seeding mixture would likely be required. A weed control plan should be initiated during the pipe removal process to address potential concerns immediately following surface disturbance.

3.8 Road, Railway, and Utility Crossings

All crossings associated with a pipeline that is being abandoned must be addressed in an appropriate manner. Of particular importance are the agreements relating to the crossings of railways, primary and secondary highways, roads, other pipelines, power lines, and communication lines, and the constraints they may place on the abandonment process.

The parameters to be considered in selecting an abandonment technique for a crossing site include the line diameter, installation details (including burial depth), subsidence tolerance, impact of excavation, impacts on other cathodic protection systems (e.g. for crossings of other pipelines), and long term development plans. Special consideration should be given to the sensitivity of roadway and railway crossings to slight ground depressions that could result from any abandonment related subsidence. The potential may also exist for disruption to crossing traffic, both during and as a result of the pipeline abandonment. As a result, more stringent abandonment requirements may be imposed, such as filling the pipeline at the crossing site with concrete or other approved material. Similarly, cased crossings may require a solid fill even if the carrier pipe is removed. [7]

The proper notification and location of the pipeline or utility being crossed is essential to maintaining a safe working environment. Operators of utilities and other pipelines may have established plans or expectations that may affect the design and timing of the abandonment. Utility crossing or pipeline crossing locations may be of concern when a pipeline is removed, due to the loss of support for the remaining facility, or the interference of the abandonment operation or the abandoned pipeline with the operation of the crossed utility or pipeline. Thus, discussions with utility and other pipeline companies will add value to the resulting abandonment plan and initiate protection planning.

The main steps of the abandonment evaluation and implementation process for any particular crossing site are as follows:

- review the existing crossing agreement and determine if there are any terms and conditions relating to abandonment-in-place or pipeline removal;
- establish communications with the utility or pipeline being crossed and negotiate terms and conditions (both technical and legal) to abandon the pipeline in place or remove the pipe;
- amend the existing crossing agreement to address the terms and conditions of the abandonment plan;
- notify all affected parties about abandonment activities and responsibilities;
- ensure that necessary approvals (e.g. from regulatory authorities, the utility being crossed, and the landowner) are obtained and kept on record;
- obtain proper location and identification of pipelines and utilities in the area using agencies such as Alberta First Call prior to commencing removal activities, and alert landowners to the activities taking place;
- file the necessary permanent records of the pipeline abandonment plan with interested parties (including pipeline regulatory authorities, provincial one-call systems, environmental groups, land titles, pipeline registers, and the affected crossing parties); and
- in the case of abandonment-in-place, ensure that the inspection requirements for the crossing are part of the post-abandonment monitoring plan.

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[7] *If the carrier pipe remains in situ, both it and the casing annulus may require a solid fill (need should be assessed on a site-specific basis.)*

3.9 Creation of Water Conduits

The potential to create water conduits as a result of the abandonment process is of concern as it could lead to unnatural drainage and material transport. This issue is primarily of concern when a pipeline is abandoned in place, since water will eventually infiltrate the pipe through perforations in the pipe wall caused by corrosion.

Unless water pathways through the pipeline are interrupted, this could lead to the unnatural drainage of areas such as muskegs, sloughs, or marshes, thus affecting the natural balance of the ecosystem. Likewise, a previously stable low area could be flooded by volumes of water exiting from a perforated pipeline. This issue can be related to the concern for contamination and the protection of wetland systems. If water infiltrates the pipeline, the potential exists for that water to carry any residual contaminants left in the abandoned pipeline to some point of exit. The point of exit could be a watercourse, thereby contaminating the watercourse if contaminant levels are sufficiently great in volume and concentration at the point of exit. The possibility of soil contamination may also exist, depending on the nature of the contaminant transported through the pipeline.

Plugs should be installed at appropriate spacings to ensure that changes in surface and ground water conditions will not result in water flow through the pipeline. When identifying locations for the plugs, consideration should be given to pipeline access during the placement of the plugs and the resulting effects of the ground disturbance. Where the pipeline crosses a wet area, a plug should be placed just downstream of the wet area, to prevent its drainage, and also at an appropriate location upstream of the wet area, to prevent the wet area contamination by water flowing along the pipeline. The plugs should be long enough so that corrosion downstream of the plug will not result in water entering the pipe.

On slopes, water could seep into the pipeline through perforations and exit at unacceptable locations such as agricultural areas or areas where excessive erosion would result. The water should be allowed to exit at frequent intervals and at preferred locations in order to minimize potential impacts from the flow of water and the disruption to natural drainage patterns. Typical locations for plugs are provided in the following table.

Table 3-1
Recommended Plug Locations

Terrain Feature	**Plug Locations**
waterbodies/watercourses	above top of bank
long inclines (>200m), river banks	at top and bottom of slope and at mid-slope for long inclines
floodplains	at boundaries
sensitive land uses (e.g. natural areas, parks)	at boundaries
near waterfalls, shallow aquifers, groundwater discharge and recharge zones, marshes, sloughs, peatlands, highwater table areas	at boundaries and should include an adequate buffer zone
cultural features (population centres)	at boundaries

The plugs should adhere to the pipe, be impermeable and non-shrinking, and able to resist deterioration. Examples of suitable materials are concrete grout or polyurethane foam. The use of impermeable earthen plugs may also be a viable option.

In the case of pipeline removal, water pathways through the uncompacted pipeline trench material must be prevented or interrupted. The principles governing the locations of trench breakers are the same as those governing the locations of plugs for pipelines abandoned in place.

3.10 Associated Apparatus

The development of any abandonment plan should also give consideration to the disconnection, removal and disposal of apparatus associated with the pipeline, including:

- aboveground valve sites and manifolds;
- underground valve sites and manifold piping, as well as protruding elements such as valve topworks;
- underground tanks;
- pipeline scraper traps;
- pipeline risers;
- line heaters;
- drip pots;
- pipeline access culverts (e.g. for tie-ins, valves, liners, etc.);
- cathodic test posts, fink stations, rectifier sites, and ground beds (to a depth of one metre);
- aboveground tanks and containment berms;
- access roads, gates, and fences;
- anchor blocks and steel piles; and
- miscellaneous apparatus such as radio antennae, buildings, fencing, wiring, electrical equipment, and slope monitoring equipment.

It is recommended that all surface and subsurface apparatus (including signage) along the route of a pipeline that is to be abandoned through removal also be removed as part of the abandonment process.

For pipeline sections that are to be abandoned in place, it is recommended that all surface apparatus as well as subsurface apparatus to a depth of at least one metre be removed, with the notable exception of signage identifying the location of the buried line pipe (i.e. line markers and aerial markers). This applies to apparatus located on operator owned land as well as apparatus located on pipeline-specific surface leases on public or private land.

Any apparatus that is left in place should be secured and properly marked and recorded, and should not pose a hazard to people, equipment, or wildlife and livestock.

3.11 Cost of Abandonment

The cost of abandoning a pipeline may be quite significant. There is a broad scope of costs to consider, from the traditional costs associated with abandonment to more intangible items such as a company's public image and the costs of environmental consequences. In order to make responsible decisions regarding abandonment, all of these costs must be considered.

The cost of abandoning a pipeline will depend on the resources required to complete the work, the value of any salvaged material, the extent of remediation and reclamation work required (as well as any associated security requirements [8]), and many other factors. Proponents should also consider the costs associated with monitoring a site and potential future remediation, as well as the consequences of the abandonment activities and any legal issues that may arise. Changes in the regulatory environment may also give rise to unanticipated abandonment costs to ensure "no responsibility by the owner/operator" after a prescribed monitoring period.

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[8] *For example, in Alberta, if an approval under EPEA is required for the abandonment of a Class 1 pipeline, security is to be provided to AEP before the approval is issued. The security amount is determined using an estimate of the cost of reclamation.*

Section 4

Post-Abandonment Responsibilities

Once a pipeline has been abandoned, the owner/operator may retain a number of responsibilities. More particularly, the owner/operator may be responsible for ensuring that the right-of-way and any facilities left in place remain free of problems associated with the abandonment. For that reason, a right-of-way monitoring program should be included in the post-abandonment plan and accounted for in the abandonment budget.

Monitoring plans will vary from case to case, depending on the location and size of the pipeline, the land use, and the features of the terrain traversed by the right-of-way (such as water crossings or slopes). When developing a monitoring plan, the effects of each abandonment issue described in Section 3 should be thoroughly examined for each specific segment of the pipeline being abandoned. Specific monitoring requirements should be included for potentially sensitive areas.

Right-of-way maintenance should also be considered in the post-abandonment monitoring plan and factored as necessary into the abandonment budget. As noted in Section 3.2, the reclamation program will normally be designed to ensure that the condition of the right-of-way is made at least equivalent to that existing just prior to the commencement of abandonment activities, and as close as circumstances permit to the condition of the land that existed prior to initial pipeline installation. The degree to which the right-of-way has to be maintained in that state depends largely on land use and environmental sensitivities. For pipe left in place, the owner/operator would normally remain responsible for the maintenance of signage.

Additionally, the owner/operator may be responsible for maintaining post-abandonment information about the pipeline. This information should be recorded in a post-abandonment log book, so that it is available when needed and can be turned over to an alternate responsible authority if required by future regulations. The post-abandonment log book should contain:

- any regulatory permits and conditions attached to permits (including reclamation certificates);
- full particulars on any pipeline facilities abandoned in place, including a physical description, location and depth of cover, plug locations, and details of any sections filled with a solid material;
- copies of all past crossing agreements;
- records of post-abandonment aerial surveillances;
- records of any slumping over the pipe, or water flow through the pipe, that was noted during post-abandonment monitoring;
- records of any changes in pipeline state from the original abandonment plan (e.g. if pipe sections abandoned in place are subsequently removed);
- records of any remedial work performed on the pipeline after abandonment; and
- records of any areas that become contaminated after the abandonment and reclamation work is complete.

The owner/operator will also be responsible for notifying landowners, municipal authorities, and other affected parties (such as one-call associations) of the abandonment of the pipeline. Any input provided by these groups should be recorded in the post-abandonment log book.

Finally, any pipeline abandoned in place should remain part of any provincial one-call program, so that third parties can be advised whether the lines they wish to have located are active or abandoned.

In closing, a major issue still to be addressed is the question of who would assume responsibility if the owner/operator becomes insolvent. In this regard, industry has established a fund in Alberta to cover the cost of reclamation and abandonment of orphaned oil and gas wells and certain associated pipeline facilities.

Appendix A

Current Regulatory Requirements

REGULATORY REQUIREMENTS FOR PIPELINE ABANDONMENT[1]					
JURISDICTION	**AGENCY**	**LAW**	**SCOPE**	**ABANDONMENT/ REMOVAL CLAUSE**	**ACTION REQUIRED**
FEDERAL	National Energy Board	*National Energy Board Act*	All pipelines	Part V, Para. 74(d)	Leave of the Board
.	.	*Onshore Pipeline Regulations*	All pipelines	Sec. 55	For abandoned facilities left in place, disconnect

					from operating facilities, fill with approved medium, seal ends, empty storage tanks then purge of hazardous vapours, and maintain cathodic protection.[2]
YUKON	National Energy Board	*Canada Oil and Gas Operations Act (COGOA)*	All pipelines	none specified	none specified
N.W.T.	National Energy Board	*Canada Oil and Gas Operations Act (COGOA)*	All pipelines	none specified	none specified
BRITISH COLUMBIA	Employment and Investment (Energy and Minerals Division)	*Pipeline Act*	All pipelines	Part II, Sec. 9	Approval of Minister. Removal of structures which may be likely to menace public safety or create a fire hazard

[1] This table lists current regulatory requirements for pipeline abandonment only and does not address the abandonment of stations or other above-ground facilities. Similarly, it does not address the requirements for pipeline deactivation or discontinuance.

[2] The NEB is in the process of amending its Onshore Pipeline Regulations and has proposed that these specific requirements be revoked, on the basis that abandonment applications will be treated on a case-by-case basis pending the outcome of the industry/government review into the matter.

REGULATORY REQUIREMENTS FOR PIPELINE ABANDONMENT (continued)					
JURISDICTION	**AGENCY**	**LAW**	**SCOPE**	**ABANDONMENT/ REMOVAL CLAUSE**	**ACTION REQUIRED**
ALBERTA	Alberta Energy and Utilities Board	*Pipeline Act*	All pipelines	Part IV, Sec. 33	Consent of the Board
.	.	*Pipeline Regulations*	All pipelines	Secs. 66-69	For facilities abandoned in place, disconnect abandoned

					pipeline from operating facilities, clean and purge with approved medium, cap all open ends and advise the Board when work is complete.[3]
.	Alberta Environmental Protection	*Environmental Protection and Enhancement Act (Alta. Reg. 115/93)*	All pipelines on private land & Green Area	Sec. 122	Reclamation Certificate from AEP
.	Alberta Agriculture, Food & Rural Development	*Environmental Protection and Enhancement Act (Alta. Reg. 115/93)*	Class I & II lines on White Area public lands	.	Reclamation Certificate from AFRD (responsibility delegated under EPEA)
SASKATCHEWAN	Department of Energy and Mines	*Pipelines Act*	All pipelines	none specified	none specified
MANITOBA	Oil and Gas Conservation Board	*The Oil and Gas Act*	All pipelines	Part 14, Sec. 171	Application to an inspector. Responsible for any repairs required within six years from the day of issuance of the Certificate of Abandonment in respect of the oil and gas facility site.
ONTARIO	Ministry of Consumer and Commercial Relations	The Energy Act	All pipelines	none specified	none specified
.	.	Gas Pipeline	Gas	none specified	none

		Systems Regulations	pipelines		specified
.	.	Oil Pipeline Systems Regulations	Oil pipelines	none specified	none specified

[3] Presently the EUB does not require the removal of an abandoned pipeline; however, in most cases it will expect a notification to the landowners, occupants, and those affected by sour gas setback distances of the abandonment. This is to ensure that affected parties are made aware of the abandonment and that their land will no longer be impacted by the pipeline.

[4] Starting in May 1997, Ontario's pipeline safety regulation program will be administered by the Technical Standards and Safety Authority, a private non-profit organization.

REGULATORY REQUIREMENTS FOR PIPELINE ABANDONMENT (continued)					
JURISDICTION	**AGENCY**	**LAW**	**SCOPE**	**ABANDONMENT/ REMOVAL CLAUSE**	**ACTION REQUIRED**
QUEBEC	Regie du Gaz Naturel	Gas Distribution Act	Gas pipelines	none specified	none specified
.	.	Regulations Respecting Gas and Public Safety	Gas pipelines	none specified	none specified [5]
NOVA SCOTIA	Energy and Mineral Resources Conservation Board	Pipeline Act	All pipelines	Sec. 20	Consent of the NSEMRCB
NEW BRUNSWICK	Natural Resources and Energy	Pipeline Act	All pipelines	none specified	none specified [6]
.	.	Pipeline Regulations	All pipelines	Sec. 85	Consent of Minister and approval of Board. For facilities abandoned in place, disconnect abandoned pipeline from operating facilities, purge with approved medium, cap

					open ends and advise Minister when work is complete. [7]
PRINCE EDWARD ISLAND	Department of Energy and Forestry	No applicable legislation	N/A	N/A	N/A
NEWFOUNDLAND	Canada-Newfoundland Offshore Petroleum Board	The Petroleum and Natural Gas Act	Offshore pipelines [8]	none specified	none specifie

Appendix B

Abandonment Checklist

1.0 **Alternate Use Analysis**

a.___Review alternate uses within company or corporate family
b.___Determine if asset can be sold to another company for continued or alternate use
c.___Decision that pipeline should be abandoned

2.0 **Product Removal & Cleaning**

2.1 Liquids Pipeline

a.___Pre-Abandonment pigging for cleaning
b.___Temporary piping modifications
c.___Temporary product measurement, storage & transportation
d.___Product removal pigging, propellant
e.___Post removal cleaning, solvents
f.___Product toxicity analysis
g.___Pipe testing for contaminants
h.___Waste disposal

2.2 Gas Pipeline

a.___Pre-abandonment pigging for cleaning/liquid removal
b.___Liquids disposal
c.___Temporary piping modifications
d.___Pressure reduction by operating facilities
e.___Pressure reduction by pulldown compression
f.___Sour/toxic product analysis
g.___Blowdown, Flaring
h.___Post removal cleaning using pigging, solvents
i.___Pipe testing for contaminants

3.0 **Information Required for Planning/Approvals**

3.1 Facility Description/History

a.___Lineal Description of the Pipeline

- pipe specification

coating
- appurtenances
- connections to other facilities
- road, highway, railroad crossings (obtain crossing agreements)
- pipeline/utility crossings (obtain crossing agreements)
- water crossings
- topography/terrain
- soil information
- weed/vegetation information
- environmentally sensitive areas
- land use/developed areas
- parallel pipelines, connections
- slope instabilities
- road accesses

b.___Operating History

- all products
- potential contamination
- operating failures/spills/clean-up
- slope movement monitoring

3.2 Regulatory Jurisdictions/Approvals

a.___Operating Authority: Liaison, Application and Approvals (Federal and/or Provincial)
b.___Environmental Authority: Liaison, Application and Approvals (Federal and/or Provincial)
c.___Public Lands Disposition (e.g. Land Administration Branch of AEP)
d.___Other Authorities: DFO, Coast Guard, etc.
e.___Municipal Authorities: Permits/Bylaws

3.3 Landowner/Public Contact Activities

a.___Title Search
b.___Landowner/Tenant Contact, Survey Clearance
c.___Abandonment Rights in Pipeline Easement/Disposition Documents
d.___Landowner/Tenant Contact/Negotiations
e.___Public Lands Managers Contact/Negotiations
f.___Release of Land Rights/Warranties/Setback Requirements
g.___Public Participation/Stakeholder Contacts (for federally regulated facilities, early public notification as per NEB's guidelines)
h.___Damage Negotiation/Payment

3.4 Environmental Assessment

a.___Soil conservation, stability (possible C&R report)
b.___Fish & Wildlife population, habitat
c.___Groundwater
d.___Erosion, stream sedimentation potential

e.___Natural Areas, Native Prairie and Native Parkland
f.___Archaeological study

4.0 **Identify Abandonment Activities (Develop Abandonment Plan)**

a.___Identification of activities required to meet regulatory requirements
b.___Identification of activities required to meet environmental conditions
c.___Economic analysis and decision regarding activities where remove/salvage andabandon in place alternatives are available.

4.1 Appurtenances Removal/Modifications

a.___Valve Assemblies, Line Heaters, Drip Pots
b.___Cathodic Protection Facilities
c.___Warning Signs, Aerial Markers, Fence Posts
d.___Access Roads, Bridges, Culverts
e.___Fences, Power lines, Antennas, Buildings
f.___Aerial Crossings
g.___Slope Monitoring Equipment
h.___Sumps and Tanks
i.___Any facility/equipment buried less that 1 m deep

4.2 Crossings

a.___Review of appropriate measures to prevent settlement/collapse and/or disturbance
b.___Liaison with Crossed Facility Operator
c.___Road, Highway Crossings
d.___Railway Crossings
e.___Water Crossings (Minor, River, Lake, Swamp)
f.___Foreign Pipeline Crossings
g.___Utility Crossings
h.___Drainage Crossings

4.3 Environmental Protection/Reclamation Activities

a.___Remediation of Historical Spill Sites
b.___Gravel Removal, Topsoil Replacement at sites
c.___Topsoil conservation
d.___Surface Stone Removal
e.___Erosion control, Ditch Plugs, Slope/Soil Stabilization
f.___Revegetation
g.___Weed Control
h.___Reforestation (if required)
i.___Access Road Reclamation
j.___Timing windows
k.___Fish and Wildlife Habitat

4.4 Pipe Removal

a.___Right-of-Way Boundary and Pipe Location Survey
b.___Access Development
c.___Grading

d.___Trenching
e.___Coating removal if required (precautions if asbestos containing)
f.___Pipe cutting and removal
g.___Pipe loading, transportation, storage
h.___Backfill/Compaction
i.___Clean-up

4.5 Salvage Analysis

a.___Sale of pipe for structural or piling applications
b.___Sale of pipe, valves, fittings for remelting scrap
c.___Sale or reuse of valves, pipe fittings
d.___Sale of fencing and other minor materials
e.___Sale of Land and/or Land Rights

4.6 Pipe Abandoned In Place

a.___ Filling to eliminate settlement/collapse risks
b.___Pipe cuts or pipeline plugs for groundwater stability
c.___Soil conservation/stability measures at excavation sites
d.___Measures to prevent floating pipe
e.___Slopes, erosion control

5.0 Monitoring/Maintenance Activities

a.___Aerial Patrol
b.___Specific site visits
c.___ Weed Monitoring/Control
d.___Liaison with landowners, tenants, public land managers
e.___ "First-Call" response and location of underground pipe
f.___ Crossings
g.___Erosion Control Maintenance

Appendix C

Industry Questionnaire

Refer to the following two pages (page 1 and page 2) for a copy of the abandonment questionnaire that was used for the industry survey conducted in autumn 1995.

Appendix D

Cleaning Guidelines

D.1 General Considerations

The operating history of the pipeline to be abandoned should be reviewed to enable the planning of the specific cleaning procedures required for abandonment. Information such as oil/gas analysis, piping modifications, operating flow records, records of anomalies, and maintenance records may provide some insight into additional work needed to develop an effective pipeline cleaning plan.

The owner/operator should ensure that there are adequate sending and receiving traps in place. This may require the use of temporary assemblies. If the pipeline in question is part of a larger system, the section to be abandoned should be physically disconnected upon completion of the cleaning process.

Safety precautions appropriate to the in-service product hazards (i.e. flammability and explosivity of hydrocarbons, toxicity of sour products) must be established throughout the activity.

For gas pipelines, any residual gas should be vented or flared once the pressure in the pipeline has been reduced to the extent possible using operating facilities or a pull down compressor. The residual gas should be monitored for signs of liquid.

For liquid pipelines, before line flow ceases, a sufficient number of scraper pigs should be run through the line to remove the bulk of any solids or waxy build-up. As illustrated by the figure below, a batch of solvent-type hydrocarbons such as diesel fuel or condensate inserted between two scraper pigs is recommended as an effective method of reducing solids or waxy build-up. This process should be repeated until solids can no longer be detected on the pigs as they are removed from the receiving trap.

Figure D-1

In-Service Initial Cleaning for Liquid Pipelines

Specialized chemical cleaning may be required if the routine cleaning method described is not successful, if the pipeline is known to have an unusually high contamination level, or if unusually high cleanliness standards are to be met. Special precautions must be exercised when the pipeline is opened up to control vapour hazards of flammability, explosiveness, and toxicity (e.g. hazardous compounds such as benzene).

D.2 Cleaning Methods for Natural Gas Pipelines

A stiff rubber scraping pig should be pushed through the pipeline (at a constant speed consistent with the pig manufacturer's recommendation) using nitrogen or some other inert gas to prevent explosive mixtures. Free liquids pushed ahead of the pig may be either pushed into the downstream pipeline section or collected in a containment tank designed and isolated according to prevailing local guidelines, for disposal in accordance with area legislation or local by-laws. This process should be repeated until free liquids are no longer evident by visual inspection. Low areas of the pipeline should be checked for the collection of liquids or other contaminants.

After these initial pigging runs, the pipeline should be checked for cleanliness. If contamination is evident, the pigging procedure should be repeated using a slug of solvent between two pigs. As with the free liquids, the solvent should be collected in a containment tank and disposed of in accordance with area legislation or local by-laws. Solvent fumes should be purged with nitrogen or a similar inert gas.

D.3 Cleaning Methods for Liquid Pipelines

Following completion of the initial in-service cleaning efforts, a final cleaning step should be done in conjunction with line evacuation. The following procedure is commonly used, although many variations exist which should be considered. Consultants specializing in the cleaning of contaminated facilities can advise and provide plans for both normal and unusual circumstances.

A slug of liquid hydrocarbons having solvent properties such as condensate or diesel fuel is pushed through the pipeline between two stiff rubber scraper pigs at a constant speed by an inert gas such as nitrogen. Other additives or treatment chemicals may be added if desired. As a rule of thumb, the volume should be calculated to maintain a minimum pipe wall contact time by the fluid ranging from five to ten minutes (or longer), depending on the effectiveness of the initial in-service cleaning process.

For lines having encrusted or high paraffin build-up, an additional volume of solvent preceding the first pig can be considered. All contact times should be increased for excessive lengths of line as the solvent may become saturated with hydrocarbons before completion of the run. The following diagram illustrates the pipeline sequence of movement. At the endpoint, the solvent and hydrocarbons are pushed into another section of pipeline or collected in a containment tank for disposal.

Figure D-2

Final Cleaning and Evaluation for Liquid Pipelines

A repeat run of the pig train described above should be conducted if there are any indications of liquids or contaminants remaining on the pipe wall in excess of the established cleanliness criteria. The effectiveness of the cleaning process can be gauged by either obtaining samples of the solvent near the tail end of the passing batch, at approximate 25 km intervals, and analyzing the samples for hydrocarbon content, or by monitoring the quality and quantity of the solvent hydrocarbons expelled from the line and comparing it with that injected.

Appendix E

Bibliography

The documents that were used in the preparation of this discussion paper are listed below. Copies of the studies that were commissioned by the Pipeline Abandonment Steering Committee are available from the Canadian Association of Petroleum Producers, the Canadian Energy Pipeline Association, the Alberta Energy and Utilities Board, and the National Energy Board.

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OVERHEAD LINE CONSTRUCTION

Fisheries and Oceans Canada
Northwest Territories Operational Statement

Version 3.0

Overhead lines are constructed for electrical or telecommunication transmission across many watercourses that range in size from small streams and ponds to large rivers, lakes and reservoirs. This Operational Statement applies to selective removal of vegetation along the right-of-way to provide for installation and safe operation of overhead lines, and passage of equipment and materials across the water body.

Although fish habitat occurs throughout a water system, it is the riparian habitat that is most sensitive to overhead line construction. Riparian vegetation occurs adjacent to the watercourse and directly contributes to fish habitat by providing shade, cover, and spawning and food production areas. It is important to design and build your overhead line project to meet your needs while also protecting riparian areas. Potential impacts to fish and fish habitat include excessive loss of riparian vegetation, erosion and sedimentation resulting from bank disturbance and loss of plant root systems, rutting and compaction of stream substrate at crossing sites, and disruption of sensitive fish life stages.

Fisheries and Oceans Canada (DFO) is responsible for protecting fish and fish habitat across Canada. Under the *Fisheries Act* no one may carry out a work or undertaking that will cause the harmful alteration, disruption or destruction (HADD) of fish habitat unless it has been authorized by DFO. By following the conditions and measures set out below you will be in compliance with subsection 35(1) of the *Fisheries Act*.

The purpose of this Operational Statement is to describe the conditions under which it is applicable to your project and the measures to incorporate into your project in order to avoid negative impacts to fish habitat. You may proceed with your overhead line project without a DFO review when you meet the following conditions:

- your planned work is not located in a critical area, as identified in a NWT Community Conservation Plan or other applicable land use plan
- it does not require the construction or placement of any temporary or permanent structures (e.g. islands, poles, crib works, etc.) below the ordinary high water mark (HWM) (see definition below),
- this Operational Statement is posted at the work site and is readily available for reference by workers, and
- you incorporate the *Measures to Protect Fish and Fish Habitat when Constructing Overhead Lines* listed below in this Operational Statement.

If you cannot meet all of the conditions listed above and cannot incorporate all of the measures listed below then your project may result in a violation of subsection 35(1) of the *Fisheries Act* and you could be subject to enforcement action. In this case, you should contact the DFO office in your area if you wish to obtain DFO's opinion on the possible options you should consider to avoid contravention of the *Fisheries Act*.

You are required to respect all local, municipal, territorial or federal legislation that applies to the work being carried out in relation to this Operational Statement. The activities undertaken in this Operational Statement must also comply with the *Species at Risk Act* (**www.sararegistry.gc.ca**). If you have questions regarding this Operational Statement, please contact the DFO office in your area (see Northwest Territories DFO office list).

We ask that you notify DFO, preferably 10 working days before starting your work by filling out and sending the Northwest Territories Operational Statement notification form (**www.dfo-mpo.gc.ca/regions/central/habitat/os-eo/prov-terr/index_e.htm**) to the DFO office in your area. This information is requested in order to evaluate the effectiveness of the work carried out in relation to this Operational Statement.

Measures to Protect Fish and Fish Habitat when Constructing Overhead Lines

1. Installing overhead lines under frozen conditions is preferable in all situations. On wet terrains (e.g., bogs), lines should be installed under frozen conditions, where possible, or using aerial methods (i.e., helicopter).

2. Design and construct approaches so that they are perpendicular to the watercourse wherever possible to minimize loss or disturbance to riparian vegetation.

3. Avoid building structures on meander bends, braided streams, alluvial fans, active floodplains or any other area that is inherently unstable and may result in erosion and scouring of the stream bed or overhead line structures.

   3.1. Wherever possible, locate all temporary or permanent structures, such as poles, sufficiently above the HWM to prevent erosion.

4. While this Operational Statement does not cover the clearing of riparian vegetation, the removal of select plants may be necessary to accommodate the overhead line. This removal should be kept to a minimum and within the road or utility right-of-way.

5. Machinery fording the watercourse to bring equipment required for construction to the opposite side is limited to a one-time event (over and back) and should occur only if an existing

crossing at another location is not available or practical to use. A *Temporary Stream Crossing* Operational Statement is also available.

- **5.1.** If minor rutting is likely to occur, stream bank and bed protection methods (e.g., swamp mats, pads) should be used provided they do not constrict flows or block fish passage.
- **5.2.** Grading of the stream banks for the approaches should not occur.
- **5.3.** If the stream bed and banks are steep and highly erodible (e.g., dominated by organic materials and silts) and erosion and degradation is likely to occur as a result of equipment fording, then a temporary crossing structure or other practice should be used to protect these areas.
- **5.4.** Time the one-time fording to prevent disruption to sensitive fish life stages by adhering to appropriate fisheries timing windows (see the *Northwest Territories In-Water Construction Timing Windows*).
- **5.5.** Fording should occur under low flow conditions and not when flows are elevated due to local rain events or seasonal flooding.

6. Operate machinery on land and in a manner that minimizes disturbance to the banks of the watercourse.

- **6.1.** Machinery is to arrive on site in a clean condition and is to be maintained free of fluid leaks.
- **6.2.** Wash, refuel and service machinery and store fuel and other materials for the machinery away from the water to prevent any deleterious substance from entering the water.
- **6.3.** Keep an emergency spill kit on site in case of fluid leaks or spills from machinery.
- **6.4.** Restore banks to original condition if any disturbance occurs.

7. Install effective sediment and erosion control measures before starting work to prevent entry of sediment into the watercourse. Inspect them regularly during the course of construction and make all necessary repairs if any damage occurs.

- **7.1.** Avoid work during wet, rainy conditions or use alternative techniques such as aerial methods (ie., helicopter) to install overhead lines.

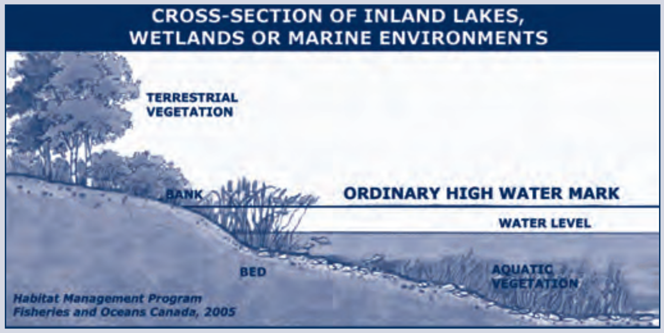
8. Stabilize any waste materials removed from the work site to prevent them from entering the watercourse. This could include covering spoil piles with biodegradable mats or tarps or planting them with grass or shrubs.

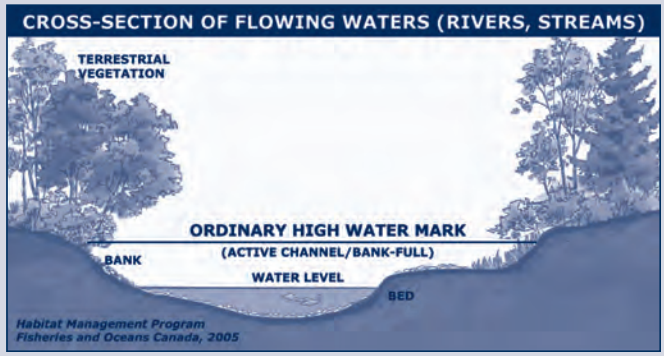
9. Vegetate any disturbed areas by planting and seeding preferably with native trees, shrubs or grasses and cover such areas with mulch to prevent erosion and to help seeds germinate. If there is insufficient time remaining in the growing season, the site should be stabilized (e.g., cover exposed areas with erosion control blankets to keep the soil in place and prevent erosion) and vegetated the following spring. If re-vegetation is not possible due to climatic extremes and/or lack of appropriate seed or stock, the site should be stabilized using effective sediment and erosion control measures. In areas with permafrost, care should be exercised to ensure these measures do not cause thawing or frost heave.

- **9.1.** Maintain effective sediment and erosion control measures until re-vegetation of disturbed areas is achieved or until such areas have been permanently stabilized by other effective sediment and erosion control measures, in the event that re-vegetation is not possible.

Definition:

Ordinary high water mark (HWM) – The usual or average level to which a body of water rises at its highest point and remains for sufficient time so as to change the characteristics of the land. In flowing waters (rivers, streams) this refers to the "active channel/bank-full level" which is often the 1:2 year flood flow return level. In inland lakes, wetlands or marine environments it refers to those parts of the water body bed and banks that are frequently flooded by water so as to leave a mark on the land and where the natural vegetation changes from predominately aquatic vegetation to terrestrial vegetation (excepting water tolerant species). For reservoirs this refers to normal high operating levels (Full Supply Level).





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DFO/2007-1329

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Directive 058—Addendum 2008-12-23

December 23, 2008

Oilfield Waste Management Facility Approvals— Notification and Amendment Procedures

The Energy Resources Conservation Board (ERCB/Board) has approved this directive on December 23, 2008.

Dan McFadyen
Chairman

Contents

1 Introduction

ERCB *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry* details the information to be submitted in an application for approval to construct and operate a new oilfield waste management facility. However, it does not address the information to be submitted to modify an existing facility. This directive sets out a notification procedure for minor modifications to existing oilfield waste management facilities and identifies those modifications that require an application to amend the oilfield waste management facility approval (WM approval). It details the information that must be submitted in a notification or an application for amendment. This directive also sets out the application process to obtain approval to conduct one-time operations or pilot projects on existing oilfield waste management facilities. As such, the scope of this directive is limited to oilfield waste management facilities for which the ERCB has issued a Board Order approving its construction and operation (i.e., a WM approval). This directive is issued as a companion to *Directive 058* and will be added to *Directive 058* in due course.

Modifications must comply with all ERCB requirements, including

- *Oil and Gas Conservation Act* and *Regulations*,
- *Directive 001: Requirements for Site-Specific Liability Assessments in Support of the EUB's Liability Management Programs*,
- *Directive 047: Reporting Requirements for the S-25 Monthly Oilfield Waste Management Facility Statement*,
- *Directive 051: Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements*,
- *Directive 055: Storage Requirements for the Upstream Petroleum Industry*,
- *Directive 056: Energy Development Applications and Schedules* (Section 2),
- *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*,
- *Interim Directive (ID) 96-3: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*,
- *ID 99-4: Deposition of Oilfield Waste into Landfills*,
- *ID 2000-3: Harmonization of Waste Management*,
- *ID 2000-4: An Update to the Requirements for the Appropriate Management of Oilfield Wastes*, and
- all other applicable requirements of the ERCB.

2 Notification Process for Minor Modifications to Approved Oilfield Waste Management Facilities

The notification process is limited to the following facility modifications:

1) addition or removal of storage tanks within an existing tank farm;
2) replacement of or upgrades to existing tank farms and bulk pads;
3) addition of a new tank farm or expansion of an existing tank farm that does not exceed criteria set out in Table 1: Addition of Tanks;
4) addition of a new disposal well to which the facility will direct wastes for deep well disposal;
5) redesignation of tanks; and
6) addition or removal of an oilfield waste stream.

If any of the above modifications includes the addition of a new waste management activity, an application for amendment must be submitted (see Section 3.2.3). For example, a new storage area for custom treating tanks must be approved if custom treating is not already occurring at the facility.

Routine replacement of existing equipment (pumps, heaters, treaters, etc.) and tanks (exchanging a tank for another tank of the same volume, provided that the dimensions of the new tank do not affect the required volumetric capacity of the dike) does not require notification.

For minor facility modifications not listed above, the approval holder must contact the ERCB Waste and Storage Section to discuss whether a notification is to be submitted for the modification.

Approval holders must submit notifications in duplicate a minimum of 15 business days prior to commencing additions or changes to the oilfield waste management facility. The ERCB will review all notifications within 15 business days. The notification may be faxed or mailed in duplicate to

ERCB Waste and Storage Section
640 – 5 Avenue SW
Calgary, Alberta T2P 3G4
Fax: 403-297-2691

If a notification is faxed, the original copy must follow by mail, and the approval holder is also encouraged to contact the ERCB Waste and Storage Section by telephone (403-297-2034) to inform them of the pending notification. The 15-business-day period begins once the notification has been received and acknowledged by the ERCB Waste and Storage Section.

The information that must be addressed in a notification is set out in Sections 2.1 and 2.2. **The ERCB will return notifications that do not address <u>all</u> of the required information to the approval holder and will consider commencement of any activity associated with the notification as a noncompliance event, in accordance with *Directive 019: ERCB Compliance Assurance—Enforcement*.**

Notifications that appropriately address all required information will be filed in the appropriate oilfield waste management facility file, and a copy will be forwarded to the appropriate ERCB Field Centre. In most situations, the WM approval will not be updated, nor will a response be sent from the ERCB. However, the ERCB may request further information regarding the notification. If the notification appears to be beyond the scope of a minor modification (e.g., the proposed modification will result in an increase to emissions, risk, or public impact), the ERCB may require that the proposed modification be processed as an application for amendment. The ERCB will notify approval holders within 15 business days of receipt and acknowledgement of a notification when such situations arise.

Any modification made to a facility without proper notification to the ERCB will be considered as a noncompliance event, in accordance with *Directive 019*. If during a facility audit or inspection, the ERCB determines that additions to an oilfield waste management facility identified in a notification do not meet all applicable requirements or are different from that described in the notification, the ERCB will initiate enforcement in accordance with *Directive 019* and will require the approval holder to take appropriate corrective action. Corrective action may include reconstructing or removal of those areas that do not meet requirements. Approval holders are required to maintain copies of all notifications at the facility site.

2.1 General Information Required for Notifications

All notifications must include

1) date of notification;
2) name, address, phone number, and fax number (including area codes) of the approval holder;
3) name of the oilfield waste management facility and its WM approval number;
4) legal land description of the facility;
5) proposed date of commencement of the activity;
6) purpose and description of the modification;
7) area of the facility where the proposed activity will occur;
8) an updated facility plot plan that clearly identifies the amended area or modification (if applicable);
9) an updated process flow diagram (PFD) for the entire facility (if applicable);
10) justification as to whether or not additional financial security will be required; if additional financial security is required, provide information regarding the financial security adjustment, in accordance with Part 16.6 of the *Oil and Gas Conservation Regulations* and *Directive 001*;
11) confirmation that *Directive 055* requirements will be met by providing a written description of the containment system(s) (i.e., specifications of primary and secondary containment systems, leak detection systems, and leachate collection systems), secondary containment capacity calculations, and appropriate engineering diagrams (if applicable); and
12) any other information the ERCB may require.

2.2 Specific Information Required for Different Modifications Covered Under Notification

The following subsections outline the specific information required to be submitted for each type of notification. This information must be provided in addition to the items listed in Section 2.1.

2.2.1 Addition or Removal of Storage Tanks Within an Existing Tank Farm

The additional information that must be submitted with the notification includes

1) number of tanks being added or removed; note that the addition of tanks must not exceed the requirements specified in Table 1: Addition of Tanks;
2) capacity of each storage tank being added or removed;
3) overall change in capacity of the facility;
4) updated notation and designation for the tank(s) (if applicable);
5) for addition of a storage tank(s), confirmation that the existing tank farm has sufficient secondary containment capacity (in accordance with Section 5.3.2.1[a] of *Directive 055*) to accept the additional tank(s) without modification; and
6) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058,* Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this notification and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

If the approval holder identified the additional tanks in the original application (i.e., future tanks), it is not required to submit notification to the ERCB or conduct public consultation. The ERCB reminds the approval holder of its responsibility to ensure that its approval is reflective of the facility (e.g., storage tanks, pads, equipment, infrastructure) and that the ERCB has an up-to-date site plan and process flow diagram.

The addition of a new waste management activity to an existing oilfield waste management facility requires an application for amendment. For example, the addition of tank(s) associated with custom treating can only occur under notification if custom treating is identified as an approved process on the WM approval for the facility and the tank farm has the capacity to accommodate the additional tank(s). If not, an application for amendment must be submitted addressing the addition of the custom treating process, as well as the storage tanks associated with custom treating (see Section 3.2.3).

Table 1. Addition of tanks

Number of tanks within an existing tank farm	Number of tanks permitted to be added to the tank farm*	Maximum volume that can be added
1-2 tanks	1	Volume of the largest tank
3-5 tanks	2	240 m^3
6-10 tanks	3	360 m^3
11-15 tanks	4	480 m^3
16-20 tanks	5	600 m^3
> 20 tanks	6	720 m^3

*The volume of each additional tank must not exceed the volume of the largest tank within the tank farm.

The volume of each additional tank must not exceed the volume of the largest tank within the tank farm. For example:

- An existing tank farm with 13 tanks where the largest tank has a volume of 100 m^3 may add up to four 100 m^3 tanks; this addition must not exceed the 480 m^3 limit.

- An existing tank farm with 13 tanks where the largest tank has a volume of 360 m^3 may add up to four tanks if the combined volume of the four tanks does not exceed 480 m^3 and the individual volume of any of the tanks does not exceed 360 m^3.

2.2.2 Replacement of or Upgrades to Existing Tank Farms and Bulk Pads

This section addresses situations where an existing tank farm or bulk pad is to be replaced or upgraded to meet current *Directive 055* requirements but the capacity of the replacement or upgraded tank farm or bulk pad does not change.

The additional information that must be submitted with the notification includes

1) updated tank notation and designation, if applicable;
2) confirmation as to whether the replacement (new) tank farm or bulk pad will be constructed in exactly the same area or a different area of the facility; if the areas are different, the updated facility plot plan required in Section 2.1(8) must clearly identify the area for both the old and new tank farm or bulk pad; and
3) if the replacement (new) tank farm or bulk pad is constructed on a different area of the facility,
   a) commitment that materials stored in the old tank farm or bulk pad will be removed within 30 days of the completion of the new tank farm or bulk pad,
   b) a description of the timeframe in which the old tank farm or bulk pad will be dismantled and the next intended use of the area, as well as a discussion as to how any contamination resulting from the old tank farm or bulk pad will be addressed, and
   c) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058*, Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this notification and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

Approval holders anticipating difficulty complying with the requirement to remove materials from old tank farms and bulk pads that have been replaced with new ones must submit notification pursuant to Section 2.2.3 for the addition of a new tank farm or expansion of an existing tank farm or Section 3.2.2 for an application for amendment for the addition of a bulk pad or expansion of an existing bulk pad. Adjustment of financial security to reflect the removal of capacity can only occur after the materials have been removed from the old storage system. Further adjustment of financial security to reflect abandonment of the storage structures and decontamination of the areas resulting from the storage systems can only occur after the respective work has been completed.

2.2.3 Addition of a New Tank Farm or Expansion of an Existing Tank Farm

The additional information that must be submitted with the notification includes

1) dimensions of the new or expanded tank farm;

2) number of storage tanks being added (note that the addition of tanks must not exceed the requirements set out in Table 1: Addition of Tanks);
3) capacity of each storage tank being added;
4) updated notation and designation for each tank (if applicable);
5) overall change in capacity for tank storage for the entire facility;
6) confirmation that the new or expanded tank farm will not result in an increase to emissions, risk, or public impact;
7) for expansion of existing tank farms, details as to how the existing containment system (i.e., dikes, liners) will be tied into the new system (including engineering diagrams) and how the integrity of the dike or liners will be ensured where the existing and new containment systems are joined; and
8) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058*, Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this notification and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

An application for amendment must be submitted if a new tank farm or an expansion to an existing tank farm does not meet the above requirements or the design of the storage system is an alternative to the requirements set out in *Directive 055* (see Section 3.2.13 of this directive).

2.2.4 Addition of a New Disposal Well

Notification for the addition of a new disposal well is limited to those facilities currently approved for fluid disposal. Notification for the addition of a new disposal well must only be submitted after all of the applicable licensing and approval requirements for the disposal well have been completed.

The additional information that must be submitted with the notification includes

1) surface location of the well;
2) well licence number and disposal scheme approval number;
3) classification of the well (i.e., class Ib or Ia);
4) statement on whether existing tanks at the facility will be associated with the new well; if redesignation of existing tanks will be required, include information outlined in Section 2.2.5; and
5) statement on whether additional storage tanks will be added to the facility to accommodate the new well; if so, refer to Sections 2.2.1 and 2.2.3.

The addition of a cavern to an existing oilfield waste management facility approved for cavern disposal may be done through notification, provided that all of the applicable licensing and approval requirements for the cavern have been completed. If the facility is not currently approved for cavern disposal, an application for amendment must be submitted (see Section 3.2.3).

2.2.5 Redesignation of Tanks

Notification for the redesignation of tanks is limited to those activities already authorized by the WM approval (e.g., an oilfield waste management facility is approved for waste processing and custom treating, and existing waste processing tanks are being redesignated as custom treating tanks).

The additional information that must be submitted with the notification includes

- a list of tanks to be redesignated, including their previous notation and new notation (if numbering of tanks is to change) and the previous use and new use.

2.2.6 Addition or Removal of an Oilfield Waste Stream

The additional information that must be submitted with the notification includes

1) oilfield waste stream(s) being added or removed (include waste code, in accordance with Table 7.4 in *Directive 058*); and
2) for the addition of an oilfield waste stream,
   a) indicate the approved waste management activities to which the oilfield waste will be subjected (e.g., waste processing, fluid disposal, storage, transfer), and
   b) confirm that the facility has the capability to manage the new waste stream.

Note that a notification may not be submitted to receive waste streams laden with naturally occurring radioactive material (NORM), waste streams requiring special handling, or non-oilfield wastes. In such cases, an application to amend the WM approval must be submitted.

3 Applications for Amendment of Oilfield Waste Management Facility Approvals

An application for amendment is required for the following modifications:

1) addition of a new tank farm or expansion of an existing tank farm that exceeds criteria set out in Table 1: Addition of Tanks or the addition of a new bulk pad or expansion of an existing bulk pad;
2) addition of a new waste management activity (e.g., deep well disposal, cavern disposal, custom treating, waste transfer, waste processing, biodegradation [biopile/biocell], landfill, tank wash, clean oil terminal);
3) change in status of a facility (e.g., active to suspended);
4) change in ownership of a facility;
5) acceptance of non-oilfield wastes, including the importation of wastes generated from the exploration and production of oil and gas outside of Alberta;
6) acceptance of material requiring special handling;
7) addition or closure of a landfill cell and closure of a landfill;
8) change in soil or groundwater monitoring programs;
9) change from sweet to sour facility;
10) expansion of lease boundaries;
11) disposition of residual wastes by an alternative method not authorized by the WM approval; and

12) requests for alternative storage (storage system that is designed or operated alternative to the requirements set out in *Directive 055*).

For facility modifications not listed above, the WM approval holder must contact the ERCB for the application requirements. Approval holders must submit an application for amendment if the proposed modification will result in an increase to emissions, risk, or public impact.

An application for amendment must be submitted in duplicate and will be registered in the ERCB Integrated Application Registry (IAR). If an activity requiring a facility ID code is added to the facility (e.g., waste processing, custom treating, or clean oil terminalling), the approval holder must obtain the facility ID code from the Petroleum Registry of Alberta and include it with the application. All applications for amendment must address the implications of the change with regard to financial security for the site. Applications that do not include this information will be deemed incomplete and may be returned to the approval holder.

3.1 General Information Required for Applications for Amendment

All applications for amendment must include

1) date of the application;
2) name, address, phone number, and fax number (including area codes) of the approval holder;
3) name of the oilfield waste management facility and its WM approval number;
4) legal land description of the facility;
5) proposed date of commencement of the activity;
6) description of the facility amendment or modification;
7) area of the facility where the proposed activity will occur (if applicable);
8) an updated facility plot plan that clearly identifies the amended area or modification (if applicable);
9) an updated PFD for the entire facility (if applicable);
10) justification as to whether or not additional financial security will be required; if financial security is required, information regarding the financial security adjustment, in accordance with Part 16.6 of the *Oil and Gas Conservation Regulations* and *Directive 001*;
11) confirmation that *Directive 055* requirements will be met by providing a written description of the containment system(s) (i.e., specifications of primary and secondary containment systems, leak detection systems, and leachate collection systems), secondary containment capacity calculations, and appropriate engineering diagrams (if applicable), or alternatively, identify that the application is for an alternative storage system; the information to address is identified in Section 3.2.13 and must be included in the application;
12) discussion of any new tracking, record keeping, or reporting requirements that will be implemented (if applicable); and
13) any other information the ERCB may require.

3.2 Specific Information Required for Different Modifications Requiring an Application for Amendment

The following subsections detail the specific information required for each activity requiring an application for amendment. This information must be provided in addition to the items listed in Section 3.1.

3.2.1 Addition of a New Tank Farm or Expansion of an Existing Tank Farm That Exceeds Criteria Set Out in Table 1

The additional information that must be submitted with the application includes

1) dimensions of the new or expanded tank farm;
2) number of storage tanks being added (if applicable);
3) capacity of each storage tank being added (if applicable);
4) updated notation and designation for tank(s) (if applicable);
5) overall change in tank storage capacity, as applicable, for the facility (as a percentage);
6) an updated notation and designation for tank(s) (if applicable);
7) for expansion of existing tank farms, details as to how the existing containment system (i.e., dikes, liners) will be tied into the new system (including engineering diagrams) and how the integrity of the dike or liners will be ensured where the existing and new containment systems are joined; and
8) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058,* Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this amendment and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

3.2.2 Addition of a Bulk Pad or Expansion of an Existing Bulk Pad

The additional information that must be submitted with the application includes

1) dimensions of the new or expanded bulk pad;
2) maximum storage capacity of the new or expanded bulk pad (if applicable);
3) overall change in bulk pad storage capacity, as applicable, for the facility (as a percentage);
4) for expansion of existing bulk pads, details as to how the existing containment system (i.e., dikes, liners) will be tied into the new system (including engineering diagrams) and how the integrity of the dike or liners will be ensured where the existing and new containment systems are joined; and
5) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058,* Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this amendment and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The

approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

3.2.3 Addition of a New Waste Management Activity

An application for the addition of a new waste management activity must include all of the required information detailed in the applicable sections of Part E of *Directive 058* specific to the type of activity being added (e.g., for addition of a transfer station to an existing oilfield waste processing facility, the application must address the transfer station application requirements in Section 22 of *Directive 058*).

The approval holder must also conduct public consultation in accordance with *Directive 056* and include the necessary documentation detailed in *Directive 058,* Sections 21.4(a) and (c) as part of the application. (Note that public consultation must occur prior to the submission of an application and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified and if concerns were identified, provide details regarding resolution of the concerns.)

The ERCB may require the application for the addition of a new waste management activity to be advertised (i.e., that a Notice of Application be placed in local and major newspapers). It will contact the approval holder in these circumstances.

For the addition of a new waste management activity, the application must identify whether the current groundwater or soil monitoring program requires augmenting and include additional site assessment information, if necessary. For facilities not currently required to perform groundwater monitoring, the approval holder should refer to the applicable sections of *Directive 058* specific to the type of activity being added to determine if a groundwater program must be implemented.

3.2.4 Change in Status of Oilfield Waste Management Facilities

The WM approval for an oilfield waste management facility must accurately reflect the status of the facility. Approval holders wishing to change the status of an oilfield waste management facility or a portion of it (e.g., change status from active to suspended, abandoned, or undergoing closure) must submit an application for amendment to the ERCB. Adjustment of financial security will only be considered after documentation has been submitted demonstrating that the work associated with the status change has been completed.

Applications requesting a change in the status of a facility or a portion of it must contain the following information:

1) For a facility or portion of a facility undergoing suspension, provide
    a) a description of the work that will be taken to
        i) eliminate all inventories—include discussion on the types of facilities to which the inventories will be sent for treatment, disposal, or recycling and the volumes of each waste type or material in inventory sent to the facilities, and
        ii) secure the facility or portion of it to ensure that no further waste management activities will occur in the suspended area;
    b) the timeframe in which the facility or portion of it will be abandoned, decontaminated, and surface land reclaimed; and

c) a commitment that all work associated with suspension activities will be documented, retained for final closure, and made available to the ERCB upon request.

2) For a facility or a portion of a facility undergoing abandonment, provide

a) a response to the applicable items under 3.2.4(1) above if the WM approval for the facility does not already reflect a suspended status (e.g., the intent of the application is to suspend the facility and follow with abandonment activities);

b) a description of the work that will be taken to remove associated equipment and structures and to abandon wells and pipelines, and a commitment that appropriate assessment work will be conducted to determine the extent, if any, of impacts caused by the waste management activity being abandoned;

c) if the facility or portion of it is to be left in an abandoned state, a description of the procedures that will be taken to secure the area and a discussion as to when the facility or portion of it will undergo decontamination and surface land reclamation work; and

d) a commitment that all work associated with suspension activities will be documented, retained for final closure, and made available to the ERCB upon request.

3) For a facility or a portion of a facility undergoing closure, provide

a) a response to the applicable items under 3.2.4(1) and (2) above if the WM approval for the facility does not already reflect a suspended or abandoned status (e.g., the intent of the application is to suspend, abandon, decontaminate, and undergo surface land reclamation of the facility or portion of it);

b) a closure plan that describes the environmental site assessment work (developed to target all potential sources, nature, and extent of contamination) and the reclamation work that will be undertaken to return the site to equivalent land capability, as well as the predicted timeframe required to conduct the work;

c) indication of whether any structures or buildings will remain on site and the reason why;

d) identification of the next intended land use (agricultural, etc.);

e) if only a portion of the facility is undergoing closure, identification of whether the reclaimed area will be removed from the facility footprint and be used for the next intended land use; and

f) a commitment that all work associated with closure activities will be documented, retained for final closure, and made available to the ERCB upon request.

4) For a facility or a portion of a facility that has undergone closure, provide a closure report that includes

a) a summary of the suspension and abandonment work undertaken;

b) the results from the environmental site assessment, including a discussion regarding the type and extent of any contamination found;

c) a summary of the work undertaken to decontaminate the site, if necessary, including confirmatory environmental site assessment work where necessary;

d) a summary of the surface land reclamation work;

e) a statement as to whether a post-closure monitoring program is necessary and, if so, the length and type of monitoring that will be required; and

f) independent verification to ensure that reclamation objectives were achieved (based on the concept of equivalent land capability) and that the site is suitable for the next intended land use.

5) For resuming operation of a facility or a portion of a facility currently suspended, provide

a) information confirming that all requirements in the applicable sections of *Directive 058* and *Directive 055* have been met; and

b) if resumption of operation of an entire facility that has been suspended for more than one year is sought, confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058,* Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this application and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

The ERCB may require the application to be advertised (i.e., that a Notice of Application be placed in local and major newspapers). It will contact the approval holder in these circumstances.

Note that because oilfield waste management facilities are not included in the definition of "specified lands" set out in the *Conservation and Reclamation Regulation* under the *Environmental Protection and Enhancement Act* (*EPEA*), they are not subject to the reclamation certification process required under that legislation. The ERCB will consult with Alberta Environment and Sustainable Resource Development (if the site is on Public Lands) to ensure that upon closure of a facility, all applicable work has been successfully completed. Once the ERCB is satisfied that the closure report contains the necessary documentation to verify that all closure requirements have been met, the WM approval will be amended to identify that closure of the facility has been completed. Through a condition of the amended approval, the approval holder will continue to be liable for the facility and site if it becomes apparent that future work is necessary as a result of activities that occurred on the site while the facility was in operation or while it was undergoing suspension or closure.

3.2.5 Change in Ownership of Oilfield Waste Management Facilities

When a facility changes ownership, an application must be submitted to transfer the WM approval to the new owner. Upon change of ownership of a facility, reimbursement of financial security to the previous owner will only occur after the new owner has posted sufficient financial security and the WM approval has been amended to reflect the new owner.

For those facilities undergoing a change in ownership, the ERCB must receive

1) written confirmation from both parties involved in the ownership change;

2) legal documentation (e.g., amalgamation certificate, purchase agreement) to confirm the change in ownership; and

3) financial security, pursuant to Part 16.6 of the *Oil and Gas Conservation Regulations*, posted by the new owner.

Note that a change in ownership of an oilfield waste management facility may require that other licences or approvals (in addition to the WM approval) also be transferred to the new owner (e.g., well licence and disposal scheme approval for a class Ia or Ib well that has the associated surface facilities approved as an oilfield waste management facility). Facility ID codes associated with the facility must also be transferred to the new owner through the Petroleum Registry of Alberta.

3.2.6 Non-oilfield Waste

Non-oilfield wastes include wastes generated from non-upstream petroleum industries in Alberta and imported wastes that have a recoverable component generated from the exploration and production of oil and gas outside of Alberta. ERCB-approved oilfield waste management facilities may receive quantities of non-oilfield wastes if an application has been submitted to the ERCB and the ERCB has approved the request. The ERCB will limit the volume of non-oilfield wastes received (combined annual total of all sources and types of non-oilfield wastes) to no more than 25 per cent of the total annual volume of oilfield wastes received at an approved oilfield waste management facility. The following sections provide the application requirements for acceptance of Alberta-generated non-oilfield waste and imported wastes generated from the exploration and production of oil and gas outside of Alberta.

3.2.6.1 Alberta-Generated Non-oilfield Waste

Non-oilfield wastes generated within Alberta must be classified as either non-hazardous or hazardous, pursuant to *EPEA*. ERCB-approved oilfield waste management facilities may receive non-hazardous and hazardous wastes if an application has been submitted to the ERCB and the ERCB has approved the request. Hazardous wastes received at ERCB-approved oilfield waste management facilities must have a recoverable component (i.e., considered to be a recyclable by Alberta Environment).

The additional information that must be submitted with the application to receive non-oilfield wastes generated within Alberta includes

1) type of non-oilfield wastes to be received and confirmation that the waste stream has similar characteristics to the oilfield waste currently approved for the facility;
2) classification of the non-oilfield waste (i.e., hazardous or non-hazardous);
3) source of the non-oilfield waste;
4) an estimate of the annual volume of each non-oilfield waste to be received and confirmation that the sum of all non-oilfield waste accepted will not exceed 25 per cent of the total volume of oilfield waste received annually;
5) a description of the acceptance procedures and methods used to verify the characteristics and classification of the non-oilfield waste; and
6) the approved waste management activities to which the non-oilfield waste will be subjected (e.g., waste processing, fluid disposal, transfer).
    a) If the non-oilfield waste is classified as hazardous, the management options must be processing for the purpose of producing a recoverable material (e.g., crude oil) or receipt for the purpose of consolidation and transfer to an approved recycling facility.
    b) If the non-oilfield waste is to be received for the purpose of consolidation and transfer to an approved recycling facility, identify the name, location, and approval

number of the receiving recycling facility and provide verification that it is authorized for such receipts.

3.2.6.2 Imported Waste Generated from the Exploration and Production of Oil and Gas Outside of Alberta

All wastes generated from the exploration and production of oil and gas being imported into Alberta are considered to be non-oilfield wastes and are subject to the waste classification (i.e., non-hazardous or hazardous), manifesting, and personal identification number (PIN) requirements set out in the *Waste Control Regulations* under *EPEA*. ERCB-approved oilfield waste management facilities may receive hazardous or non-hazardous imported wastes that have a recoverable component (considered to be a recyclable by Alberta Environment) if they are generated from the exploration and production of oil or gas, an application has been submitted to the ERCB, and the ERCB has approved the request.

The additional information that must be submitted with the application to receive imported non-oilfield wastes includes

1) a copy of the written ministerial authorization for importation of hazardous recyclables and the hazardous waste receiver registration (PIN) from Alberta Environment if the wastes are classified as hazardous;
2) the type of imported wastes to be received (applicable waste code from Table 7.4 of *Directive 058*) and confirmation that the imported waste is from the exploration and production of oil and gas;
3) an estimate of the annual volume of each imported waste to be received and confirmation that the sum of all imported and non-oilfield waste accepted will not exceed 25 per cent of the total volume of oilfield waste received annually;
4) a description of the acceptance procedures and methods used to verify the characteristics and classification of the imported waste;
5) identification of the recoverable component of the imported waste and a description of the process used to produce a recoverable material from the imported waste; and
6) the approved waste management activities to which the imported waste will be subjected (e.g., waste processing, transfer).
   a) If the imported waste will be received for purpose of consolidation and transfer to an approved recycling facility, identify the name, location, and approval number of the receiving recycling facility and provide verification that it is authorized for such receipts.

3.2.7 Acceptance of Material Requiring Special Handling

The additional information that must be submitted with the application includes

1) a detailed description of the material requiring special handling to be accepted at the facility, including its source;
2) a description of the waste acceptance and handling procedures;
3) a detailed description of how the waste will be managed at the facility (e.g., waste processing, storage, waste transfer);
4) name, location, and approval number of the facility to which the residual wastes will be sent for further treatment or disposal; and

5) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058*, Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this application and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

3.2.8 Addition or Closure of a Landfill Cell and Closure of a Landfill

Oilfield waste management facilities consisting of an oilfield landfill must submit an application for amendment for the addition of a landfill cell, closure of a landfill cell, or closure of the entire landfill.

The additional information that must be submitted with the application includes the following:

1) For the addition of a landfill cell, the approval holder must
    a) provide all of the applicable information detailed in the Alberta Environment *Standards for Landfills in Alberta* (as updated) and Section 25.0 of *Directive 058*; and
    b) conduct public consultation if the new landfill cell will extend beyond the initial footprint of the landfill. Provide confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058*, Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this application and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns. The ERCB may also require the application to be advertised and will notify the approval holder in these circumstances.)
2) For the closure of a landfill cell or an entire landfill, the approval holder must provide all of the applicable information detailed in the Alberta Environment *Standards for Landfills in Alberta* (as updated) pertaining to final closure and post-closure care.

3.2.9 Change in Soil or Groundwater Monitoring Programs

An approval holder that wishes to change a facility's current soil or groundwater monitoring program or propose an alternative monitoring program that differs from what is outlined in *Directive 058* or described in the WM approval must submit an application for amendment.

The additional information that must be submitted with the application includes

1) a description of the current monitoring program for the facility and the reasons for the change; and
2) a description of the proposed monitoring program, including
    a) frequency of monitoring,
    b) parameters that will be tested for (if applicable),

c) addition of groundwater monitoring wells (including their location on an updated plot plan) or changes to existing groundwater monitoring wells (if applicable), and

d) a description of any alternative monitoring systems that will be used (e.g., soil vapour surveys, soil sampling surveys, shallow geophysical techniques [electrical conductivity, electromagnetic, or ground-penetrating radar surveys]).

3.2.10 Change from Sweet to Sour Facility

The additional information that must be submitted with the application includes

1) a description of the waste acceptance procedures for the sour material, including whether sour material will be neutralized prior to unloading;

2) a description of the modifications to the facility to accommodate sour material, including provisions to control odours during receiving, processing, and disposing of sour material (e.g., vapours routed through a vapour recovery unit or flare stack); and

3) confirmation and documentation that the approval holder has conducted public consultation in accordance with *Directive 056*, including the necessary documentation detailed in *Directive 058,* Sections 21.4(a) and (c). (Note that public consultation must occur prior to the submission of this application and must allow participants [landowners, occupants, residents, and stakeholders] a minimum of 14 calendar days to receive, consider, and respond to the consultation of the proposed development. The approval holder must disclose whether any concerns were identified; if concerns were identified, provide details regarding resolution of the concerns.)

3.2.11 Expansion of Lease Boundaries

The additional information that must be submitted with the application includes

1) written confirmation indicating that the landowner has consented to the lease expansion;

2) an updated plot plan that clearly identifies the area and dimensions of the expanded lease area;

3) a description of the activity proposed to occur in the expanded lease area; and

4) a discussion as to whether the lease expansion requires a change in the soil or groundwater monitoring program and, if so, the information set out in Section 3.2.9; and

5) a detailed account of the required site investigation in the area of the expanded lease to determine the baseline soil conditions. This investigation must include determining the physical characteristics (texture, particle size, evidence of fracturing, internal drainage characteristics, and an estimate of moisture content) and chemical characteristics (pH, electrical conductivity, sodium absorption ratio, major ions [Ca, Mg, Na, Cl, SO_4, K], cation exchange capacity, total metals, benzene, toluene, ethylbenzene, and xylene [BTEX], and petroleum hydrocarbon fractions F1, F2, F3, and F4) of the soil. This information, including the locations in which the samples were taken, must be provided with the application. The approval holder must also determine whether additional groundwater monitoring wells are required as a result of the expansion. If the approval holder considers a site investigation or additional groundwater monitoring wells unnecessary for the lease expansion, the approval holder is required to provide justification in the application.

3.2.12 Disposition of Residual Wastes by an Alternative Method Not Authorized by the WM Approval

The additional information that must be submitted with the application includes

1) a description of the residual wastes to be disposed of by the alternative method, including the characterization and classification of the material;
2) the estimated annual volume of residual material to be disposed of by the alternative method; and
3) the name, location, and operator of the alternative treatment or disposal facility, a description of how the residual wastes will be managed there, and confirmation that the facility is approved to accept the material.

3.2.13 Alternative Storage Systems

An approval holder wishing to implement storage systems alternative to the requirements in *Directive 055* must submit an application for amendment. The alternative storage design must provide a level of environmental protection and safety equivalent to the original in order to meet the objectives and intent of *Directive 055*.

The additional information that must be submitted with the application for an alternative storage system includes

1) a description of the waste streams or materials that will be stored within the system;
2) methods for receiving and removing materials from the storage system to ensure that spills, leaks, and tracking of material outside the system will be prevented;
3) design of the primary and secondary containment systems, leak detection systems, and leachate collection systems, including details of the construction materials and any liner specifications;
4) detailed engineering diagrams, including cross-sectional diagrams, showing the primary and secondary containment, leak detection, and leachate collection systems to comply with the information requirement in Section 3.1(11) of this directive;
5) total storage capacity of the system (in cubic metres); and
6) details of the storage system safety features, such as overfill/release protection measures (e.g., high-level shutdown, alarms at an attended facility).

If the alternative storage system involves the addition of a new storage area, tank farm, or bulk pad or an expansion to an existing tank farm or bulk pad, the approval holder must provide a project-specific information package to the landowners, occupants, and residents who may be directly and adversely affected by the activity and indicate whether any concerns were identified. If concerns were identified, the approval holder must provide details regarding resolution of the concerns. Public consultation must occur prior to the submission of an application and must allow participants a minimum of 14 calendar days to receive, consider, and respond to notification of the proposed development.

4 One-time Approvals and Pilot Projects on Approved Oilfield Waste Management Facilities

An application for a one-time approval is required for a temporary activity that is not currently approved, such as the acceptance of a waste stream resulting from an emergency or unique situation.

An approval holder interested in testing a new waste management process or technology or an existing waste management process or technology with a unique waste stream on an ERCB-approved oilfield waste management facility must submit an application requesting approval for a pilot project. Pilot project and one-time applications must obtain written approval prior to commencement.

Pilot project and one-time applications will be registered in IAR. Once an approval has been granted, any changes or amendments to a pilot project or one-time approval must be approved by the ERCB. Notifications will not be accepted. Approval holders wishing to permanently integrate the process or technology tested through a pilot project must submit an application for amendment (see Section 3.2.3) and obtain the amended WM approval prior to continuation of the activity.

4.1 Applications for One-time Approvals and Pilot Projects

Applications for one-time approvals and pilot projects must include

1) date of the application;
2) name, address, phone, and fax number (including area codes) of the approval holder;
3) name of the oilfield waste management facility and its WM approval number;
4) legal land description of the oilfield waste management facility;
5) proposed date of commencement of the activity;
6) duration of the one-time activity or pilot project (e.g., 6 months) and amount of material to be tested or treated (e.g., 1000 m^3);
7) a description of the pilot project, including its purpose and the criteria to be used to measure success of the project (pilot projects only);
8) a description of the waste acceptance procedures, as well as the procedures used to verify composition, volume, characterization, and waste classification;
9) a discussion of the methods to be used to manage residual liquids and/or solids;
10) a site plan identifying the location of all infrastructure (e.g., storage systems, equipment) associated with the one-time activity or pilot project (if applicable);
11) a PFD (if applicable);
12) a discussion of how the infrastructure associated with the one-time activity or pilot project will meet *Directive 055* requirements to ensure environmental protection (if applicable);
13) engineered design diagrams (if applicable); and
14) a description of the record keeping program to be implemented.

4.2 Completion of a Pilot Project

Upon completion of a pilot project, the approval holder must submit a report detailing

1) total volume of each waste type managed by the pilot project;
2) volume of products and residuals generated, as well as the disposition location of these materials;
3) any operational problems encountered and how they were overcome;

4) whether the pilot project was successful, including the data and rationale used to make this determination; and
5) indication of intention to permanently incorporate the process or technology. If positive, include the potential timing for submission of an application. If negative, include the timing for dismantling and removal of equipment associated with the pilot project.

Oilfield Waste Management Requirements for the Upstream Petroleum Industry

November 1996

Effective January 1, 2008, the Alberta Energy and Utilities Board (EUB) has been realigned into two separate regulatory bodies, the Energy Resources Conservation Board (ERCB), which regulates the energy industry, and the Alberta Utilities Commission (AUC), which regulates the utilities industry.

As part of this realignment, the title pages of all existing EUB directives now carry the new ERCB logo. However, no other changes have been made to the directives, and they continue to have references to “EUB.” As new editions of the directives are issued, these references will be changed.

ENERGY RESOURCES CONSERVATION BOARD
Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry

November 1996

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Oilfield Waste Management Requirements for the Upstream Petroleum Industry

November 1996

GUIDE RENAMED AS A DIRECTIVE

As announced in *Bulletin 2004-02: Streamlining EUB Documents on Regulatory Requirements,* the Alberta Energy and Utilities Board (EUB) will issue only "directives," discontinuing interim directives, informational letters, and guides. Directives set out new or amended EUB requirements or processes to be implemented and followed by licensees, permittees, and other approval holders under the jurisdiction of the EUB.

As part of this initiative, this document has been renamed as a directive. However, no other changes have been made. Therefore, the document text continues to have references to "guides." These references should be read as referring to the directive of the same number. When this directive is amended, these references will be changed to reflect their renaming as directives.

Alberta Energy and Utilities Board

Guide 58 Oilfield Waste Management Requirements for the Upstream Petroleum Industry

First Edition November 1996

Printed and published by the Alberta Energy and Utilities Board

Additional guides are available at $50.00 each from EUB Information Services at (403) 297-8190.

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FOREWORD

On 3 December 1992, a multi-stakeholder Steering Committee was established to oversee the work of several subcommittees that jointly prepared a draft of oilfield waste management requirements for the Energy Resources Conservation Board (ERCB), now the Alberta Energy and Utilities Board (EUB). These requirements were implemented on 1 September 1993 when the ERCB assumed jurisdiction for the regulation of upstream oilfield wastes.

The draft report, *Recommended Oilfield Waste Management Requirements*, and IL 93-8 were a compilation of the:

> Alberta Environmental Protection and Enhancement Act (EPEA) and Regulations,
> Alberta Environmental Guidelines,
> Requirements written into Licences to Operate,
> Oil and Gas Conservation Act and Regulations, and
> ERCB Informational Letters, Interim Directives, and General Bulletins.

Following the release of the document, a new Steering Committee was established in January 1994 to oversee a broad public/government/industry review of the Recommended Oilfield Waste Management Requirements. Individuals who served on the Steering Committee are:

Don Beamer, Chairman	Alberta Energy and Utilities Board
Silver Lupul	Alberta Environmental Protection
Scott McClure	Alberta Special Waste Management Corporation
Kim Johnson	Canadian Association of Petroleum Producers
Harvey Hittel	Canadian Association of Petroleum Producers
Tim Taylor	Canadian Association of Petroleum Producers
Ken Byram	Alberta Oilfield Treating and Disposal Association
Ross Huddleston	Environmental Services Association of Alberta
Myles Kitagawa	Toxic Watch Society
Richard Chant	Pembina Institute for Appropriate Development

Input was also provided by Alberta Health and the Health Unit Association.

Following the completion of the review in April 1994, the Steering Committee compiled the responses and identified areas of the document that required further work. As the review of each area was completed, either by a subcommittee or independently by the EUB, the information was tabled with the Steering Committee for ratification and consolidation into the requirements. As a result, some of the requirements within this document, *Oilfield Waste Management Requirements for the Upstream Petroleum Industry*, represent new policy.

The Steering Committee would like to thank all of those who worked on the subcommittees and especially Susan Halla, Steve Skarstol, and Meg Bures of the EUB for their extensive work on various subcommittees and in compiling much of the document.

PART A

POLICIES AND RESPONSIBILITIES

Part A

Policies and Responsibilities

1.0 Introduction

This document addresses a wide range of waste management issues that apply to oilfield wastes. It represents a consolidation of information on all oilfield waste management matters that come under the jurisdiction of the Alberta Energy and Utilities Board (EUB) and other issues which indirectly affect the management of wastes that are produced by the upstream oil and gas industry in Alberta.

The principles and purpose of these requirements are to:

- Describe the EUB's expectations on how the Alberta upstream oil and gas industry should manage oilfield wastes.

- Identify the oilfield waste management responsibilities of the licensee and/or approval holder.

- Promote waste volume minimization involving reuse, recycle, reduce, and recover philosophies.

- Require the recording, retention, and submission of oilfield waste information that will assist in compliance with waste management practices.

2.0 Responsibilities and Enforcement

2.1 Responsibilities

1. Waste Generator

The oilfield waste generator (i.e. licensee and/or approval holder) is responsible for ensuring that:

- these requirements are followed,
- waste minimization is considered when appropriate,
- oilfield wastes are properly characterized,
- appropriate treatment and disposal practices are utilized,
- the capabilities and limitations of any waste treatment and disposal method are known,
- accurate and complete waste documentation and manifesting is maintained,
- waste carriers and receivers have been informed of the oilfield waste's properties, and
- the required approvals and operational requirements are in place for any on-site handling, treatment, and disposal method.

2. Waste Receiver

The oilfield waste receiver is responsible for ensuring that:

- the required approvals and operation requirements are in place for any on-site waste handling, treatment, and disposal method,
- the capabilities and limitations of their treatment and disposal facilities are known and waste generators are informed of the limitations,
- only waste is received for which their facility is approved to handle,
- accurate and complete waste documentation and manifesting is maintained,
- their operations are in compliance with licences and approvals, and

- equipment and operating practices are upgraded as necessary to comply with changes in regulatory requirements.

2.2 Enforcement

1. EUB

The EUB believes that enforcement is one part of a total program of regulation, information, distribution, and enforcement, all of which are designed to achieve:

"An energy industry that understands, respects, and meets or exceeds regulations and standards often through the implementation of self-imposed guidelines."

This vision states clearly that compliance is the responsibility of the energy industry. The EUB expects that all industry players will understand its requirements and have an infrastructure in place to ensure compliance. At the same time, the EUB believes that, on occasion, enforcement of regulations will also be required to ensure compliance and to meet the vision of the enforcement policy, as explained in the EUB's Enforcement Brochure, issued August 1996.

2. AEP

Oilfield waste facilities are specifically excluded from requiring an approval under Alberta Environmental Protection and Enhancement Act (EPEA). Some waste facilities may be part of a larger site, such as a sour gas plant, which also requires an approval from Alberta Environmental Protection (AEP). Because of this exclusion, the waste facilities will not be subject to the EPEA Waste Control Regulation. They may be subject to Environmental Protection Orders (EPOs) and Enforcement Orders (EOs) under a variety of sections of EPEA, including the Contaminated Sites section. EPOs are issued to persons deemed "responsible", and if the conditions of the order are not met, an EO under Section 200 of EPEA may be issued along with the associated fines.

3.0 Importation of Oilfield Waste

1. Wastes generated outside of Alberta resulting from the exploration and production of oil and gas and **exhibit** the properties that would classify the wastes as:

   - **dangerous waste** in accordance with the Transportation of Dangerous Goods Act (TDG),
   - **hazardous waste** in accordance with EPEA, and
   - **dangerous oilfield waste** in accordance with Section 5.0 of this document:

     (a) shall not be imported into Alberta for the purpose of direct disposal, or

     (b) shall not be imported into Alberta for the purpose of treatment or disposal at EUB approved facilities,

     (c) may be imported into Alberta for the purpose of treatment, provided the wastes are directed into the Alberta Special Waste Management System, which is under the jurisdiction of AEP, and

     (d) shall not be temporarily stored in Alberta for a period that exceeds 30 days.

2. Wastes that are generated outside of the province of Alberta during the exploration and production of oil and gas and **do not exhibit** the properties that would classify the wastes as **dangerous wastes, hazardous wastes, or dangerous oilfield wastes** may be imported into Alberta for purpose of treatment and/or disposal.

3. Licensees and/or Approval Holders of facilities under the jurisdiction of the EUB wanting to receive wastes identified in point (2) above, must:

   (a) for existing facilities, apply to the EUB to amend the current facility approval or licence to allow the receipt of imported wastes, or

   (b) for proposed facilities, include in their application for approval to construct and operate, the intention to receive imported wastes streams and the waste source.

PART B

WASTE CHARACTERIZATION AND CLASSIFICATION

Part B

Waste Characterization and Classification

4.0 Introduction to Waste Characterization

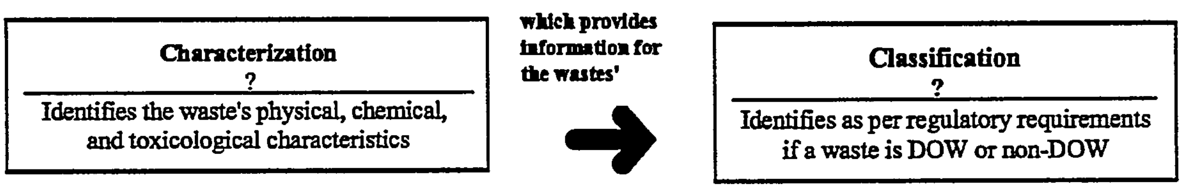
4.1 Overview

The waste generator is responsible for properly characterizing each waste (see Table 4.1a, *Properties of Dangerous Oilfield Wastes*). The waste characterization is then used in assessing the appropriate handling, treatment, and disposal of that waste. Waste characterization is the assessment of the physical, chemical, and toxicological characteristics (i.e. properties) of a waste. There are two primary reasons for characterization:

- to determine the dangers relating to transportation on public roads, and
- to determine the environmental consequences of the waste so that a disposal or management option that appropriately deals with those consequences may be used.

Once an oilfield waste has been characterized, it can be classified into one of two classifications; dangerous oilfield waste (DOW) or non-dangerous oilfield waste (non-DOW) (see Table.4.1a, *Properties of Dangerous Oilfield Wastes* and Table 4.1b, *Dangerous Oilfield Wastes*). Recommended test methods for waste characterization are provided in Appendix 3.0, *Recommended Test Methods*.

Figure 4.1 Characterization versus Classification



4.2 Responsibilities

It is expected that all reasonable efforts will be made by the waste generator to minimize the production of wastes prior to addressing the issue of disposal (refer to Appendix 6.0, *Waste Minimization*). The EUB strongly encourages the conservation of resources through minimization prior to the disposal of residual wastes.

In all cases, it is the responsibility of the waste generator to ensure that each waste has been properly identified, characterized and handled, treated, and disposed in a proper manner.

4.3 Transportation Requirements

The Federal Transportation of Dangerous Goods Act and Regulations (TDG) identifies requirements for the transportation of dangerous goods. The Alberta Department of Transportation and Utilities (ATU) administers TDG within Alberta utilizing the provincial Transportation of Dangerous Goods Control Act and Regulations (TDGC). Licensees and/or approval holders should ensure that their personnel have proper TDG training.

DOWs which are transported on public roads must be manifested as per the requirements in Part C, *Waste Manifesting and Tracking*. A waste's shipping name, product identification number (PIN), transportation class, and other important information necessary for manifesting DOWs can be found in the schedules of the TDG regulations.

A number of the waste handling and transportation classifications have been identified for wastes listed in Section 7.4 of Appendix 7.0, *Waste Management Table*.

Table 4.1a

Properties of Dangerous Oilfield Wastes

Flammability	• Waste has a flashpoint less than 61°C. • Waste ignites and propagates combustion in a test sample.
Spontaneous Combustion Potential	• Waste generates heat at a rate greater than it loses heat and reaches the auto-ignition temperature.
Water Incompatibility	• Waste generates flammable or explosive gases in contact with water.
Oxidizing Potential	• Waste contributes oxygen for combustion at a rate that is equal to or greater than that provided by either ammonium persulphate, potassium perchlorate or potassium bromate.
Toxicity	• Waste has an oral toxicity LD50 not greater than 5 000 mg/kg. • Waste has a dermal toxicity LD50 not greater than 1 000 mg/kg. • Waste has an inhalation toxicity LC50 not greater than 10 000 mg/m^3 at normal atmospheric pressure.
Corrosivity	• Waste has a pH value less than 2.0 or greater than 12.5.
PCB Content	• Waste contains polychlorinated biphenyls at a concentration equal to or greater than 50 mg/kg.
Leachate Toxicity	• Waste is a liquid or a solid that passes a 9.5 mm mesh opening, or a friable solid that can be reduced by grinding in a mortar and pestle to a particle size that passes a 9.5 mm mesh opening, or a mixture of these, and i) it contains at a concentration of 100 mg/L or higher any substance listed in Table 1 of the Schedule to the *Alberta Users Guide for Waste Managers*, published by AEP, ii) the leachate contains any substance listed in Table 2 of the Schedule to the *Alberta Users Guide for Waste Managers*, in excess of the concentrations listed in Table 2, or iii) contains any of the following substances in a concentration greater than 0.001 mg/L: hexachloro-dibenzo-p-dioxins pentachloro-dibenzo-p-dioxins tetrachloro-dibenzo-p-dioxins hexachloro-dibenzofurans pentachloro-dibenzofurans tetrachloro-dibenzofurans.

Table 4.1b

Dangerous Oilfield Wastes

Dangerous Oilfield Wastes	**The following are dangerous oilfield wastes:** i) waste types listed in Table 3 of the Schedule to the *Alberta Users Guide for Waste Managers*, published by AEP, ii) commercial products or off-specification products listed in Part A of Table 4 of the Schedule to the *Alberta Users Guide for Waste Managers*, iii) commercial products or off-specification products listed in Part B of Table 4 of the Schedule to the *Alberta Users Guide for Waste Managers*, iv) wastes with any of the properties as per Table 4.1a, *Properties of Dangerous Oilfield Wastes*, or v) containers as identified in Section 5.3, *Dangerous Oilfield Waste Containers*.

5.0 Procedures for Classifying Wastes

5.1 General Procedure

Wastes must be classified as either DOW or non-DOW based on the criteria outlined in Table 4.1a, *Properties of Dangerous Oilfield Wastes* and Table 4.1b, *Dangerous Oilfield Wastes*. Figure 5.1, *Classification of Oilfield Waste,* is a graphical representation of the classification procedure for determining whether an oilfield waste is dangerous or non-dangerous.

Sufficient historical data exists for some waste streams whereby common acceptable treatment and disposal practices have been established. These oilfield waste streams are included in Section 7.4 of Appendix 7.0, *Waste Management Table*. It is important for generators to understand that Section 7.4 of Appendix 7.0 does not cover all cases and testing may be required before determining appropriate treatment and disposal methods. Where classification of a waste is unclear, refer to AEP's *Alberta Users Guide for Waste Managers* for further information.

5.2 Dangerous Oilfield Waste

Oilfield wastes with any of the properties defined in Table 4.1a or are classified as a DOW as per Table 4.1b are considered dangerous oilfield wastes. These wastes may have a variety of properties with varying safety and environmental consequences. Properties may include flammability, pyrophoric characteristics, oxidizing potential, water incompatibility, toxicity, corrosivity, etc. Wastes with these properties require special attention to ensure they are handled, treated, and disposed of properly. Test methods for the properties identified in Table 4.1a can be found in Appendix 3.0, *Recommended Test Methods*.

5.3 Dangerous Oilfield Waste Containers

Figure 5.1, *Classification of Oilfield Waste,* also includes information regarding the procedure to classify oilfield waste containers. Further information on containers is described below.

1. Any container or collection of containers with an aggregate internal volume greater than 5 litres (L) must be handled and disposed of as DOW if:

   (a) it contains a substance listed in Part A of Table 4 of the Schedule to the *Alberta Users Guide for Waste Managers,* published by AEP, and it is not an empty container, or

   (b) it contains or did contain a substance listed in Part B of Table 4 of the Schedule to the *Alberta Users Guide for Waste Managers* and it is not a rinsed empty container.

2. An empty container means a container that contains less than 2.5 centimetres (cm) of residue remaining at the bottom of the container or less than 3 per cent of the original contents, whichever is the lesser amount.

3. A rinsed empty container means a container that has been rinsed three times using for each rinse a clean solvent that is in an amount equal to 10 per cent of the container volume and that is capable of removing the contained waste, or an equivalent method. If it is not tested, the rinsate should be classified the same as the container waste or the rinse solvent, whichever is more stringent.

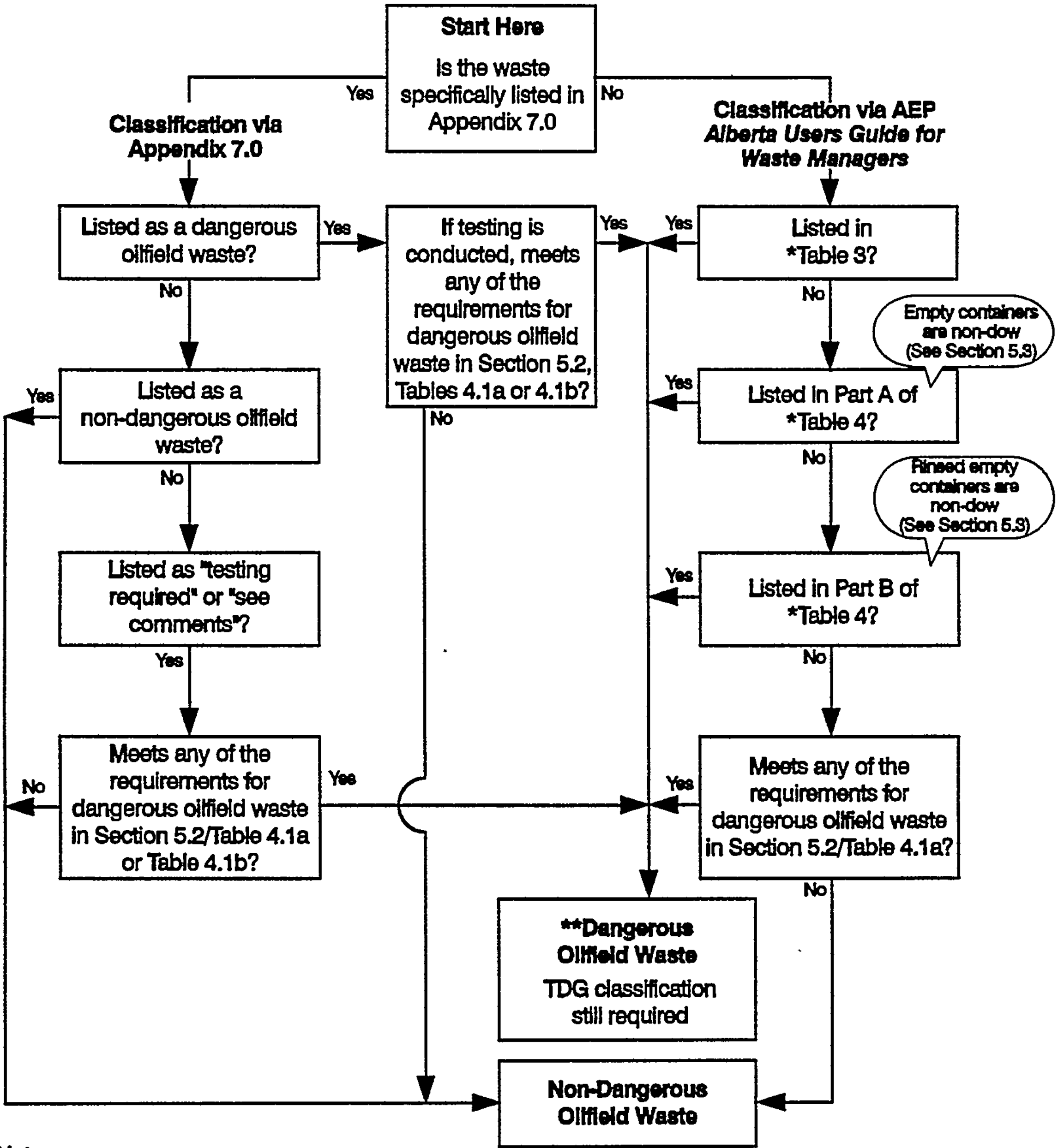
5.4 Small Volumes

For the purposes of these requirements, oilfield wastes (other than those substances listed in Part B of Table 4 of the Schedule to the *Alberta Users Guide for Waste Managers* published by AEP) are not considered dangerous if they are produced at any single site in an amount less than 5 kilograms (kg) per month if a solid or 5 litre (L) per month if a liquid, and the total quantity accumulated does not exceed 5 kg or 5 L at any time.

5.5 Mixing and Dilution

Oilfield waste must **not** be mixed with any solid or liquid for the primary purpose of dilution to avoid any Alberta regulatory requirements.

Figure 5.1 Classification Of Oilfield Waste



Notes:

* Refers to schedules listed at the back of the *Alberta Users Guide for Waste Managers.*

** Not considered DOW if produced at a single site in volumes <5 kg or <5 L per month and does not exceed this amount at any time when accumulated (does not apply to Part B, Table 4 listed wastes in the *Alberta Users Guide for Waste Managers*).

- Classify container rinsate as per container waste or the rinse solvent, whichever is more stringent.
- For complete classification requirements see Section 5.2, Tables 4.1a and 4.1b and Section 5.3 for containers.

6.0 Wastes Banned from Disposal via Injection into Pipeline Systems

Upstream oilfield wastes that can be separated from the production stream and can be harmful to downstrean oil handlers must not be diluted by injection into pipelines. Pipelines must not be thought of as a "mixing vessel" for waste dilution.

For safety, environmental, corrosion, operational, and economic reasons, the oilfield wastes identified in this subsection are **banned** from direct injection into any pipeline system. The rationale for this decision is based on the wastes':

non-hydrocarbon content,
chemical composition,
water content,
solids content, and/or
the availability of practical, cost effective waste treatment methods.

6.1 Banned Waste Types

- All motor, engine, driver, and compressor hydrocarbon and synthetic lubricating oils, unless specific written agreements have been made with the receiving refinery. Alternative acceptable waste management methods such as recycling and reclaiming are available. It is the responsibility of the pipeline company to confirm that the wastes were received by the refinery.
- All non-hydrocarbon based wastes.
- All solid wastes.
- All non-hydrocarbon based drilling fluids.
- All fracturing sands.
- All radioactive wastes.
- All halogenated solvents and halogenated organic chemicals (i.e. organic chlorides).
- All water based wastes including, but not limited to, produced water, acid water, process water, water based methanol hydrotest fluids, other water based hydrotest fluids, wash fluids, boiler blowdowns, filter wash fluids, and oily water.
- All chemical based sludges including, but not limited to, glycol sludges, gas sweetening sludges, and other process sludges.

- All chemical wastes, whether "unused" pure, spent, or contaminated. This includes, but is not limited to, all caustics, acids, laboratory chemicals, PCBs, gas sweetening agents, non-hydrocarbon based surface and downhole treating chemicals, glycols, methanol, and treating or softening salts.

PART C

WASTE MANIFESTING AND TRACKING

Part C

Waste Manifesting and Tracking

7.0 Introduction To Waste Manifesting and Tracking

This section outlines the manifesting and tracking requirements for generators and receivers of oilfield waste in Alberta.

An integral component of proper waste management is the use of documents (manifests) to ensure wastes are safely transported and received at their intended point of treatment and/or disposal.

Waste tracking is an equally important component of proper waste management. For the purpose of these requirements, waste tracking refers to a system by which the handling, movement, treatment, and disposal of wastes are monitored by the waste generator.

7.1 System Summary

Dangerous oilfield waste (DOW) transported on public roads in Alberta must be manifested (see Section 8.2, *When to Use a Manifest*). The EUB's Alberta Oilfield Waste Manifest is to be used for the transportation of DOWs within Alberta. If the oilfield waste is transported into or out of Alberta (i.e. crosses a provincial or federal border), generators must classify, name, and label their waste in compliance with TDG. This includes usage of the federal manifest (regulated by AEP in Alberta). The EUB Oilfield Waste Manifest is replaced by the federal manifest for shipments of oilfield waste into or out of Alberta.

Oilfield waste generators must implement a waste tracking system that ensures the quantities and characteristics of all generated wastes, both dangerous and non-dangerous, as well as their final treatment and disposal methods are known. Generators are responsible for the safe and proper handling, treatment, and disposal of all generated waste.

Selected licensees and/or approval holders of wells or other facilities will be required to prepare an annual oilfield waste disposition report. These reports must contain summarized information pertaining to the type, quantity and ultimate treatment and/or disposal of oilfield wastes, including those treated and/or disposed on-site. Some oilfield wastes are exempt from this waste disposition report requirement. All DOWs must be included. In addition, Table 9.1, *Reportable Oilfield Wastes*, lists the other waste types, which may or not be dangerous, that must be included in the waste dispostion report. All miscellaneous DOWs, as well as any miscellaneous non-DOWs which represent a risk to the environment or public safety, must be reported. There is a section in Section 7.4 of Appendix 7.0, *Waste Management Table*, for miscellaneous waste codes which can be used to report these unlisted waste types.

The reporting requirements identified in this section in no way exclude generators or receivers from any other requirements outlined in EUB legislation, Interim Directives, Informational Letters, or General Bulletins.

8.0 Manifesting

8.1 Background

Manifests include specific information about the waste, its source and its destination. These documents provide detailed information to first responders in the event of an accident, and serve as a tool for confirming that shipments of dangerous wastes are properly handled, transported, and disposed.

Many oilfield wastes are classified as dangerous waste (see Section 5.2, *Dangerous Oilfield Waste*) and are required to be manifested if transported on public roads (see Sction 8.2, *When to Use a Manifest*). The EUB Alberta Oilfield Waste Manifest was designed to meet the document requirements of TDG for shipments of DOW occurring entirely within Alberta.

The Alberta Oilfield Waste Manifest is a 5- page EUB form (see Figure 8.1, *Manifest, [Front Page]*). This form will be available from Information Services (EUB) on the ground floor of the Energy Resources Building. Specific instructions for the completion of the Alberta Oilfield Waste Manifest are also included with each manifest (see Figure 8.2, *Manifest, [Back page]*).

8.2 When to Use a Manifest

1. **EUB Alberta Oilfield Waste Manifest**

   (a) The EUB Alberta Oilfield Waste Manifest must be completed and accompany the waste shipment when transporting DOWs on public roads in Alberta. The shipment must occur entirely within the province of Alberta. This includes shipments transported to AEP approved facilities. For shipments not occurring entirely within the province of Alberta, the federal manifest (regulated by AEP in Alberta), must be used (see federal manifest section).

   (b) The EUB Alberta Oilfield Waste Manifests are **not** required for the following:

      i) when the quantity of DOW transported does not exceed 5 kg or 5 L,

      ii) when the waste is a non-DOW*,

         * companies wishing to use the EUB Alberta Oilfield Waste Manifest as a tracking document for non-DOWs must indicate on the manifest that the waste is non-dangerous.

Copies of the manifests completed for non-DOWs are **not** to be sent to the EUB.

iii) when the oilfield wastes are treated/disposed on-site,

iv) when the waste is uncontaminated produced water (contaminants which would make the produced water a DOW, must not be present),

v) when the DOW is transported from the site of origin to another site, provided the licensee or approval holder of both sites are the same, and

- the person in charge of the vehicle transporting the DOW displays on the vehicle a placard that corresponds to the placard set out as Figure 19 in Part II of Schedule V of the Federal Regulations, and

- the shipment is accompanied by a shipping document that shows the hazard class, the emergency response contact, the total mass or volume of the DOWs to which the shipping document relates, and the number of packages where applicable, or

vi) when the manifest documentation requirements for the DOWs are exempted by a valid and appropriate Permit for Equivalent Level of Safety (see Section 8.4, *Permits for Equivalent Level of Safety*).

2. Federal Manifest (Regulated by AEP in Alberta)

The following waste shipments require completion of the federal manifest (copies submitted to AEP and/or Environment Canada):

(a) DOWs transported across provincial/territorial/international boundaries (copies must be submitted to the appropriate Federal and/or State and/or Provincial governments, as required), and

(b) DOWs, which have been received at a transfer station approved by AEP for the receipt of industrial waste, and which are subsequently consolidated and transported for treatment and/or disposal (copies of the federal manifest must be submitted to AEP). When DOWs are received at AEP approved transfer stations, they are considered "Industrial Wastes" for the purpose of further transportation.

8.3 General Manifest Requirements

Notwithstanding the requirements of Section 8.2, *When to Use a Manifest*, a manifest is required for each load of DOW being transported. However, where a single truck must make several trips to move the entire quantity of a specific oilfield waste, a single manifest may be used with attachments documenting each load. Where more than one truck is used to move a quantity of the specific oilfield waste, each truck must carry a manifest, with attachments for repeat trips if necessary.

If the information requirements in any particular case exceed the limitations of the manifest, it is acceptable to use attachments provided their existence is indicated on the manifest.

Note: Copies of all attachments must be made for, and kept with each page to which they apply.

8.4 Permits for Equivalent Level of Safety

TDG allows a Permit for Equivalent Level of Safety to be granted to a waste generator (or association) for the purpose of reducing manifest documentation requirements where appropriate. The Alberta Department of Transportation and Utilities (ATU) may grant such a permit upon receipt of a satisfactory application.

8.5 Mixed Wastes

Shipments of mixed wastes comprised of several waste types must be manifested as the most dangerous waste contained if the individual quantities of each waste type are not known. Indicate the total volume of the waste on the manifest. The waste generator should indicate on the manifest or attachment the waste types included in the mixed waste shipment.

8.6 Waste Identification

The shipping name identified on the EUB Alberta Oilfield Waste Manifest, which is used to describe the waste, **must** be determined in accordance with TDG. The corresponding oilfield waste code must be determined from Section 7.4 of Appendix 7.0, *Waste Management Table*. In all cases, the product identification number (PIN) identified on the manifest must correspond to TDG.

8.7 Manifesting System

Figure 8.3, *Manifesting Procedure*, shows the responsibilities of all parties relative to manifesting, along with the movement and distribution of the manifest document.

8.8 Reconciliation of Discrepancies - EUB Manifest

Discrepancies between waste details entered by the waste generator in Part A of the EUB manifest and waste details entered by the receiver in Part C of the manifest must be reconciled by the generator.

1. **Serious Discrepancies**

If the receiver notes a **serious** discrepancy regarding the quantities or characteristics of the waste shipped relative to what was received, the receiver must notify the generator and the transporter within **24 hours** of the time received. A **serious** discrepancy is one which may have resulted in an impact to the environment (i.e. spills, leakage, waste does not arrive at intended receiver) or one where the waste received differs **significantly** from the waste sent by the generator. In cases where a **serious** discrepancy is the result of an action by the transporter (i.e. accident, leak, etc.) the transporter must notify the generator within **24 hours** of the occurrence. In the event of being notified of or becoming aware of a **serious** discrepancy, the waste generator must notify the EUB as soon as possible by the quickest, most effective means available (during normal work hours, 8:00 am - 4:30 pm, Monday to Friday, phone the *Waste Manifest Coordinator*, Facilities Division, Calgary Office and during weekends or evenings, phone the appropriate EUB Field Office).

The EUB does not have jurisdiction over many of the waste disposal facilities (AEP approved) or the transporters. As a result, the EUB expects the waste generators to have procedures in place between themselves and the transporters and receivers regarding this **24 hour** notification requirement.

2. **All Discrepancies**

The Generator is to send the completed Page 1 of the manifest to the EUB within **60 days** of the shipment date. In situations where the generator is not able to reconcile any discrepancy within **60 days** from the date of shipment, the *EUB Waste Manifest Coordinator* must be notified.

It is recognized that the accurate measurement of waste quantities in the field is difficult and may vary depending on the waste type and method of containment/transportation. Waste generators must use sound judgement when recording waste quantities on the manifest and when reconciling discrepancies (see Section 10.0, *Waste Accounting*, for additional information on measurement).

8.9 Retention of Manifests

Manifest copies and supporting documentation must be retained by all parties (generator, transporter, and receiver) for a minimum of **two years** from the date of shipment. All documentation is subject to EUB audit.

Figure 8.1 Manifest (Front Page)

EUB Alberta Energy and Utilities Board

Alberta Oilfield Waste Manifest

Manifest No.

A) GENERATOR (CONSIGNOR)

COMPANY NAME	OPERATOR CODE (GENERATOR):
ADDRESS	PROV:
CITY	POSTAL CODE:
SOURCE SITE LOCATION	
BATTERY/FACILITY CODE	OPERATOR CODE (FACILITY):
INTENDED RECEIVER	
ADDRESS	PROV:
CITY	POSTAL CODE:
RECEIVING SITE LOCATION	BATTERY/FACILITY CODE:

B) TRANSPORTER (CARRIER)

COMPANY NAME:		ADDRESS	
CITY:		PROV:	POSTAL CODE
DATE:	UNIT NO:	TELEPHONE:	FAX

Certification - I declare that I have received wastes as offered by the Generator in PART A for delivery to the Intended Receiver and that the information contained in PART B is correct and complete.

NAME (PRINT):	SIGNATURE

C) RECEIVER (CONSIGNEE)

COMPANY NAME:		ADDRESS	
CITY:		PROV	POSTAL CODE:
RECEIVING SITE LOCATION		BATTERY/FACILITY CODE	OPERATOR CODE

N or D	SHIPPING NAME/DESCRIPTION OF WASTE	ALTA PERMIT NUMBER	WASTE CODE	TDGA/PIN	CLASS	PACKING GROUP	HANDLING CODE	QUANTITY SHIPPED	UNITS	OIL %	WATER %	SOLID %	QUANTITY RECEIVED	UNITS	OIL %	WATER %	SOLID %	HAND CODE	TRANS DECON

SPECIAL HANDLING/EMERGENCY INSTRUCTIONS

DATE SHIPPED	TIME SHIPPED	SCHEDULED ARRIVAL DATE

Certification - I declare that the information in PART A is correct and complete.

NAME OF AUTHORIZED PERSON (PRINT)	SIGNATURE	FAX	CELLULAR
		TELEPHONE	24HR EMERGENCY NO

IF HANDLING CODE '02' OR '21' SPECIFY

DATE RECEIVED	TIME RECEIVED

IDENTIFY DISCREPANCIES BETWEEN WASTE RECEIVED AND DETAILS LISTED IN PART A (USE ATTACHMENTS IF NECESSARY)

Certification - I declare that the information contained in PART C is correct and complete.

NAME OF AUTHORIZED PERSON (PRINT):	TELEPHONE
SIGNATURE	

D) GENERATOR (CONSIGNOR): COMPLETE UPON RECEIPT OF MANIFEST FROM RECEIVER

EXPLANATION OF REASON FOR DISCREPANCIES NOTED BY RECEIVER (IF ANY), AND WHAT CORRECTIVE ACTION HAS BEEN TAKEN (Use attachments if necessary):

NAME OF AUTHORIZED PERSON (PRINT)	SIGNATURE	DATE	TELEPHONE

EP MANI 96 10 **Press Firmly and Print Clearly**

Distribution: White - EUB, Yellow - Generator, Pink - Receiver, Goldenrod - Transporter, Blue - Generator (see back for details)

Alberta Energy and Utilities Board 640 - 5 Avenue SW, Calgary, Alberta Canada T2P 3G4

Figure 8.2 Manifest (Back Page)

Alberta Authority Responsible for Oilfield Waste Manifests - ALBERTA ENERGY AND UTILITIES BOARD
Facilities Division
640 - 5 Avenue SW, Calgary, Alberta T2P 3G4
(403) 297-8170

MANIFEST INSTRUCTIONS

Distribution:

1. Generator completes PART A and has Transporter complete PART B. Generator detaches and retains Page 5 (blue).
2. Transporter carries Pages 1 (white), 2 (yellow), 3 (pink) & 4 (goldenrod) with shipment and gives them to the Receiver. **Note: If a serious discrepancy is the result of an activity by the Transporter (e.g. truck spill) the Transporter must notify the Generator within 24 hours.**
3. Receiver completes PART C, noting any discrepancies, then returns Page 4 (goldenrod) to Transporter and Pages 1 (white) and 2 (yellow) to Generator **(to be sent no later than 30 days after the waste shipment date)** and retains Page 3 (pink). **Note: If a serious discrepancy is noted, the Generator and Transporter must be notified within 24 hours.**
4. Upon being notified of a serious discrepancy or receipt of Pages 1 (white) and 2 (yellow), Generator investigates any discrepancies noted by the Receiver and takes corrective action. **The EUB must be notified immediately if a serious discrepancy is noted. If the generator cannot reconcile discrepancies within 60 days after the date of the waste shipment, the EUB must be notified.** Investigation results and corrective action are to be reported in Part D (or Attachment). Generator sends page 1 (white) to the EUB **(to be sent no later than 60 days after the waste shipment date).**
5. Companies wishing to use the manifest for non-dangerous oilfield wastes must indicate on the manifest that the waste is non-dangerous. **Copies of the manifests used for only non-dangerous oilfield wastes are not to be sent to the EUB.**

NOTE: All parties must retain MANIFEST copies and supporting data for a minimum of 2 years.

Completion: some information listed below may not be applicable in all situations.

Part A - Generator (Consignor)

- Identify **Company Name, Operator Code** (EUB assigned codes), and **Business Address.**
- Identify **Source Site Location** (reported as **LSD - Sec - Twp - Rge - W M**), **Battery/Facility Code** (EUB assigned codes), and **Operator Code** (Licencee/Waste Generator may be different than facility operator).
- Identify **Intended Receiver, Business Address, Receiving Site Location** (reported as **LSD - Sec - Twp - Rge - W M.**) and **Receiving Battery/Facility Code** (EUB or AEP assigned codes).
- Identify if the waste is Non Dangerous **(N)** or Dangerous **(D).**
- **Shipping Name/Description of Waste** - From Transportation of Dangerous Goods Regulations (TDG).
- **Alberta Permit No.** - Obtained from Alberta Transportation & Utilities.
- Identify **Waste Code** (EUB assigned codes - see Appendix 7.0 of Guide 58).
- **TDGA/PIN and Classification** - Obtained from TDG.
- **Packing Group:**
  - I - Very Dangerous
  - II - Dangerous
  - III - Moderately Dangerous
- **Handling Code** - See Part C Receiver (Consignee) for appropriate Handling Code.
- **Quantity Shipped** - Report to nearest 0.1 m³ or 0.1 tonne.
- Indicate **Units** of shipment (t = tonne, m = m³).
- Identify **Oil/Water/Solid %** where applicable.
- **Special Handling/Emergency Instructions** - Self Explanatory.
- Identify **Date, Time Shipped,** and **Scheduled Arrival Date.**
- Print **Name, Telephone/Fax/Cellular Numbers,** and **Sign** form.
- Identify **24 Hour Emergency Telephone Number.**

Part D - Generator (Consignor)

- Upon receipt of pages 1 (white) & 2 (yellow) - Enter **Discrepancy Reconciliation Details** (if any) and **Corrective Action**
- Print **Name, Date, Telephone No.,** and **Sign** form.

Part B - Transporter (Carrier)

- Identify **Company Name, Business Address, Date,** Truck Unit No., and **Telephone and Fax Number.**
- Print **Name** and **Sign** form.

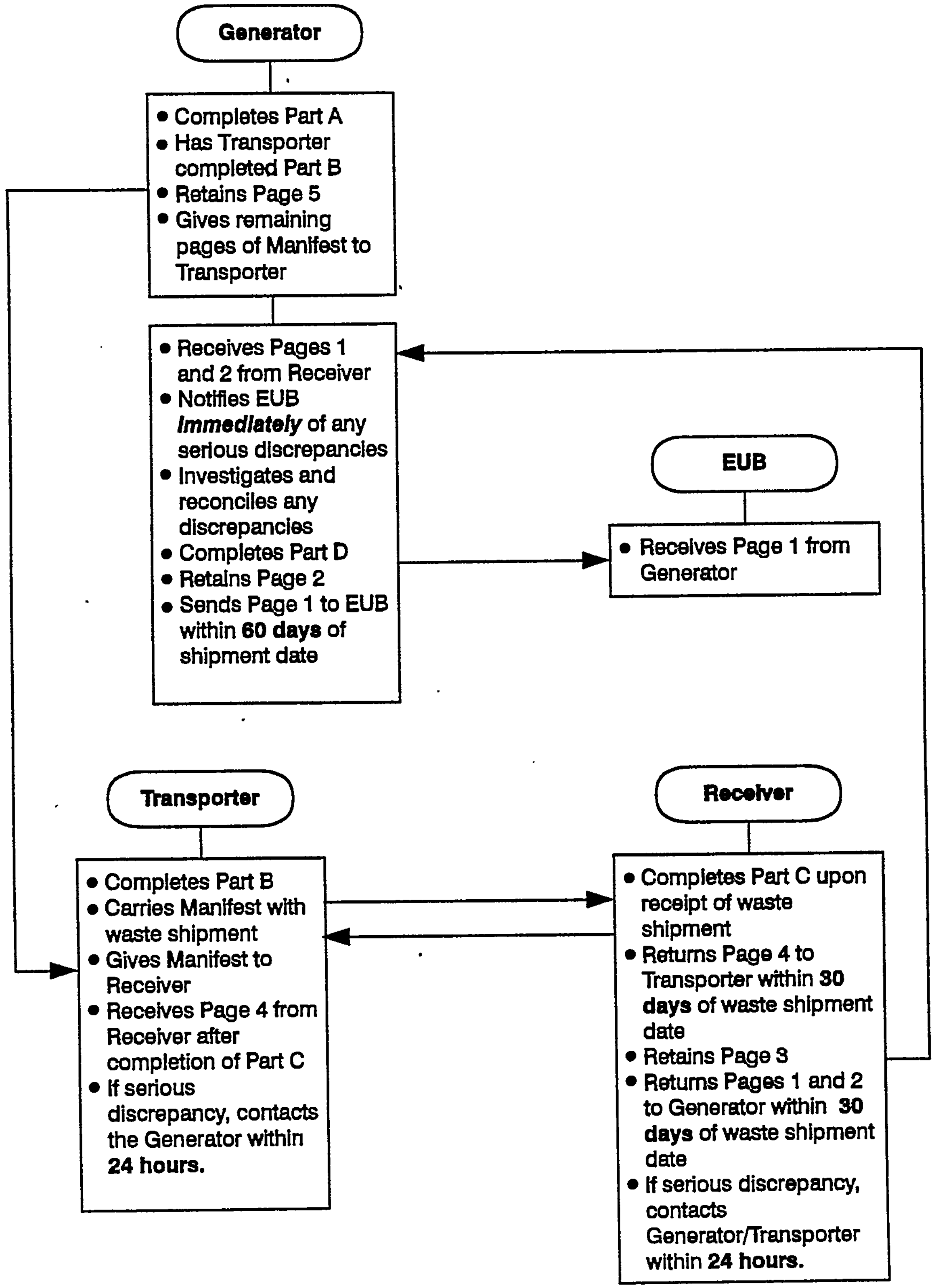
Part C - Receiver (Consignee)

- Identify **Company Name** and **Business Address.**
- Identify **Receiving Site Location** (reported as **LSD - Sec - Twp - Rge - W M**), **Battery/Facility Code** (EUB or AEP assigned codes), and **Operator Code.**
- **Quantity Received** - Report to nearest 0.1 m³ or 0.1 tonne.
- Indicate **Units** of shipment (t = tonne, m = m³).
- Identify **Oil/Water/Solid %** where applicable
- **Handling Code** - Enter code for method of handling: (refer to Definitions in Appendix 8.0 of Guide 58).

01	Storage Facility	**12**	Thermal Treatment
02	Transfer Station (specify intended treatment/disposal)	**13**	Biodegradation Facility
03	Oilfield Waste Processing Facility	**14**	Small Oilfield Waste Incinerator
04	Class Ia Disposal Well	**15**	Used Oil Recycler
05	Class Ib Disposal Well	**16**	Recycling Facility (excluding used oil)
06	Class II Disposal Well	**17**	Swan Hills Facility
07	Cavern	**18**	Road Spreading
08	Class Ia Landfill	**19**	Biodegradation (on site)
09	Class Ib Landfill	**20**	Burial (on-site)
10	Class II Landfill	**21**	Other (specify)
11	Class III Landfill		

- **Transporter Decontaminated** - Enter Yes or No.
- **If Handling Code 02 or 21 - Specify** - Describe treatment/disposal (i.e., location/method)
- Identify **Date and Time Received**
- Identify **Discrepancies** - Self Explanatory
- Print **Name** and **Telephone Number,** and **Sign** form.

Figure 8.3 Manifesting Procedure



9.0 Tracking

9.1 Background

Waste tracking is required from the time of initial generation of the waste through to final disposition (cradle to grave). The effective tracking of oilfield waste is essential to aid the waste generator in ensuring the proper handling, treatment, and disposal of oilfield wastes. The tracking system must enable the generator to demonstrate compliance.

9.2 Generator Responsibilities

Waste generators are responsible for tracking their wastes from "cradle to grave". In keeping with this philosophy, generators must be aware of the quantities and types of waste they generate, how they are handled, and where and how they are ultimately disposed. Therefore, in the case of waste being delivered to a facility between the generator's site and the final disposal site (delivery to a transfer station), the waste generator is responsible for obtaining details of final disposition from the transfer station operator. The generator is responsible for ensuring appropriate treatment and disposal of the waste occurs.

All waste generators are required to implement and maintain a waste tracking system. The development and type of system used is solely their choice and preference. All tracking systems must be effective and capable of displaying due diligence. The system must also be capable of providing information required for the oilfield waste disposition report (see below).

Tracking system data is to be maintained for a minimum of two years and is subject to EUB audit.

1. **Oilfield Waste Disposition Reports**

   The oilfield waste disposition report is a summary of the types and quantities of disposed oilfield wastes, the point(s) of generation/consolidation and the specific disposal method(s) utilized. All DOWs and many non-DOWs which are treated/disposed must be included.

   Specific licensees and/or approval holders of wells or other facilities will be selected each year and notified that their annual oilfield waste disposition report for the previous calendar year must be submitted to the EUB. Companies selected will be notified by 15 January and will be given until 28 February to comply with this request. Therefore, the EUB expects that all licensees and/or approval holders of wells or other facilities will collate their tracking data to enable the 43-day request for the report to be met. Furthermore, at anytime after

28 February of each year, the EUB could request the annual report (or portion thereof), from any company. This company would be given only 30 days to comply.

2. Report Submission and Processing Information

(a) The oilfield waste disposition report must include summary data which identifies all the sources (facilities or locations) of waste disposed. Sources include:

i) point of generation - the facility or location where the waste was generated. This refers to sites where waste was treated/disposed on-site or sent directly for disposal.

ii) point of consolidation - the facility or location where the waste was consolidated from a number of sites prior to disposal.

(b) The waste disposition report must include summary data regarding the waste types, quantities disposed and disposal method(s) utilized.

(c) All DOWs as well as those wastes listed in Table 9.1, *Reportable Oilfield Wastes,* which are disposed, including those treated and/or disposed on-site, are to be included in the waste disposition report. Miscellaneous DOWs and non-DOWs which represent a risk to the environment or public must also be included in the report. Oilfield waste treated in-situ does not have to be reported.

(d) Appendix 8.0, *Oilfield Waste Disposition Report*, shows the required data elements for the oilfield waste disposition report. Descriptions of the data elements can be found in Section 8.1 of Appendix 8.0, *Instructions to Complete the Oilfield Waste Disposition Report.* The report computer data format can be found in Section 8.2 of Appendix 8.0, *Computer Data Format.* This is the format the file must be in for submission to the EUB.

(e) Requested waste disposition reports must be submitted to the EUB on 3.5" computer diskettes. Paper copies of reports will not be accepted.

(f) Reprocessing fees will be charged for errors, missing data, and late/missing reports.

(g) The waste generator must include in their report, any waste disposed by service companies which was generated in association with the generator's operations.

3. Reporting Oilfield Wastes Not Listed in Waste Management Table (Section 7.4 of Appendix 7.0)

Section 7.4 of Appendix 7.0, *Waste Management Table*, is a reasonably comprehensive list of oilfield wastes generated in the upstream oil and gas industry. However, some wastes generated in the oil and gas industry will not be captured by this list. A section in the *Waste Management Table* has been included for Miscellaneous Wastes. These wastes are based on the TDG class system (i.e. Class 4 for flammable solids). The main purpose of this section is to provide waste codes under which these wastes can be tracked and reported. The generator selects the miscellaneous waste code which corresponds to the TDG class of the waste and then uses this code for reporting.

Table 9.1

Reportable Oilfield Wastes

All DOWs must be included in the annual oilfield waste disposition report. Additionally, the following oilfield wastes which may or may not be dangerous, must be included in the report. Non-DOW that are not included in this list, but are specified in the *Waste Management Table*, Section 7.4 of Appendix 7.0 are exempted from the waste disposition report unless they are determined to be dangerous.

This list is only for the annual oilfield waste disposition report requirement. (It is **not** intended to be used for classifying oilfield wastes.)

- Absorbants
- Activated Carbon
- Asbestos
- Boiler Blowdown Water
- Catalyst (non•sulphur)
- Catalyst (sulphur)
- All Contaminated Debris and Soils
- Crude Oil/Condensate Emulsions (Residuals after treatment)
- Desiccant
- Filters (media) • water treatment
- Filters • air pollution control
- Filters • lube oil
- Frac Sand (radioactive and non•radioactive)
- Glycol Solutions (no heavy metals)
- Hydraulic and Transmission Oils
- Incinerator Ash (if incinerated material is reportable)
- Ion Exchange Resin
- Ion Exchange Resin Regenerant Liquids
- Lubricating Oil
- Pigging Waste
- Contaminated solids less than 50 ppm Polychlorinated Biphenyls (PCBs)
- Produced Sand
- Sludges • (flare pit, hydrocarbon, lime, process, and sulphur)
- Sweetening Agents • (solids and liquids)
- Treater Hay
- Wash Fluids (organic)
- Water•Process (with organic chemicals)
- Water•Process (neutralized solutions with heavy metals)
- Water•Produced (if contaminants are present which make the solution a DOW)
- Well Workover Fluids
- Wood • chemically treated/cooling tower
- Unlisted Wastes (if they present a risk to the environment or the public)

10.0 Waste Accounting

10.1 Measurement

The accurate measurement of waste is often difficult, if not impossible, due to the varied nature of waste and the difficulties caused by the presence of solid materials. The best available measurement technology for the given circumstances should be utilized.

Whenever possible, volume determinations should be made using metres, tank gauges or weigh scales. In situations where the use of such devices is not possible, estimated volumes should be based on the dimensions of the container used to store or transport the waste.

Where appropriate, the components of a waste should also be determined (i.e. oil, water, and solids). Representative samples should be centrifuged to determine the proportionate quantities of each component.

10.2 Units for Manifesting and Waste Disposition Report

The oilfield waste disposition report and the EUB oilfield manifest require the waste to be reported in either tonnes or cubic metres. Often the waste is contained in drums or other various containers which can make quantity determination difficult. The following criteria is suggested to enable consistent reporting:

1. **Drummed liquid waste**: For the manifesting and reporting requirements, sum the volume of waste in all the drums and convert to m^3.

   Example: 6 drums of liquid waste (205 litre drums).
   Calculation: 6 drums x 205 L/drum x 1m^3/1000 L = 1.23 m^3.

2. **Drummed solid waste**: For the manifesting and reporting requirements, sum the weight of waste in all the drums and convert to tonnes. If the density of the solid waste is known, calculate using the actual density.

   If the weight of the solid waste is not known, assume the density = 1 kg/L

   Using the assumption of 6 drums (205 L each)
   Calculation: 6 drums x 1 kg/L x 205 L/drum x 1 tonne/1000 kg = 1.23 tonnes.

3. **Bulk packaged waste**: For other bulk packaged wastes, report the solid waste in tonnes and liquid waste in cubic metres. If the weight of the bulk solid waste is unknown but the volume of the container is known apply 1 L = 1 kg for general conversion/estimation.

PART D

OILFIELD WASTE MANAGEMENT FACILITIES

PART D

11.0 Oilfield Waste Management Facilities

11.1 Introduction

The **purpose** of this section is to outline the general requirements for oilfield waste management facilities to ensure that public health and the environment are adequately protected and that the site can be readily restored for the next intended land use.

An oilfield waste management facility may consist of one or more of the following components:

waste storage area/facility,
waste transfer station,
waste processing facility,
surface facilities associated with waste disposal wells,
waste disposal well (Class Ia or Ib),
cavern,
landfill,
biodegradation facility,
thermal treatment facility, and
other oilfield waste management technology or facility.

Applicants considering any of the waste management components listed above should review the following subsections, 11.2 - 11.9, for general requirements that are applicable to all oilfield waste management components/facilities. Although the text tends to refer to waste management facilities, the general requirements are also applicable to licensees and/or approval holders who intend to integrate a waste management component into an EUB approved oil and gas or oil sands facility. Additional requirements that are specific to a particular type of waste management component/facility are addressed in Sections 12 to 17. These sections also indicate whether the integration of a waste management component into an existing EUB approved facility requires notification or application. Refer to Part E for the information that is required in an application for approval to construct and operate an oilfield waste management facility.

11.2 Siting Issues

Siting considerations must be incorporated into the design of oilfield waste management facilities. The following site related factors must be considered when locating a possible site for an oilfield waste management facility:

1. minimizing the risk of environmental damage including any impact to the quality of surface water and groundwater, and the health of humans, animals, and plants during construction, operation, and closure of the facility,

2. avoid drainage ways and areas subject to seasonal flooding,

3. not to be located within 100 metres (m) of the normal high water mark of a body of water, permanent stream, or water well used for domestic purposes, and

4. avoid environmentally sensitive areas or areas where the public is directly impacted.

11.3 Safety Issues

1. An oilfield waste management facility shall be designed, constructed, and operated such that it complies with the regulations stipulated under the following Acts and associated Regulations:

   Oil and Gas Conservation Act,
   Occupational Health and Safety Act (and the Workplace Hazardous Material Information System),
   Safety Codes Act (Alberta Fire Code), and
   Environmental Protection and Enhancement Act.

2. Notwithstanding the requirements stated in Section 11.3 (1), oilfield waste must be handled in such a manner that it does not:

   (a) produce fugitive air emissions or uncontrolled gases which exceed AEP Ambient Air Quality Guidelines,
   (b) produce uncontrolled fumes or gases sufficient to pose a risk of fire or explosion, or
   (c) threaten public health, safety, or the environment through other means.

3. A perimeter fence shall be installed to prevent public and wildlife access to the waste management facility.

4. An oilfield waste management facility shall bear signs as per Section 6.020 and Schedule 12 of the Oil and Gas Conservation Regulations, at the entrance of the facility identifying facility name, operator name, emergency phone number, and legal description.

5. All waste management facilities shall comply with equipment spacing requirements identified in Sections 8.030 (2), 8.080 (2) and (3), and 8.090 of the Oil and Gas Conservation Regulations.

6. A corporate response plan shall be maintained on-site at all times which describes appropriate measures to follow in the event of any emergency such as a fluid spill, tank fire or any other hazard. Employees must be trained in respect to normal and emergency situations. All phone numbers and contacts should be updated periodically. For information regarding preparation of a corporate-level response plan, refer to ID 91-2, *Preparation of Corporate Level Response Plan*, or any subsequent publication issued.

7. Licensees and/or approval holders must ensure their facilities meet the Noise Control Directive, ID 94-4.

8. As per Informational Letter IL 96-10, *A Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*, all unrefined product spills must be reported to the local EUB field office. Refined product and chemical spills are the responsibility of the Pollution Control Division of AEP.

11.4 Waste Characterization

Licensees and/or approval holders of waste management facilities are responsible for knowing the capabilities and limitations of their treatment technologies and as such, must only accept wastes exhibiting the properties their facility is approved to handle. Generally, this will require waste characterization, unless the stream is sufficiently well known through either prior testing or an in depth knowledge of the origin of waste. Refer to Appendix 3.0 for *Recommended Test Methods*.

11.5 Environmental Impact Assessment (EIA)

It is the applicant's responsibility to determine the need for an EIA. AEP is the government agency responsible for the EIA process. Refer to section 19.0, *Environmental Impact Assessments*, for the administrative process to follow.

11.6 Design and Operation

Licensees and/or approval holders must design and operate the facility to minimize impact to the air, groundwater, surface water, or soils on or around the site. The following factors must be taken into consideration at the design stage and during operation of the facility:

1. Material storage in accordance with EUB ID 95-3 and Guide G-55, *Storage Requirements for the Upstream Petroleum Industry*. This includes adherence to the construction, secondary containment, leak detection, and weather protection provisions outlined for above-ground tanks, underground tanks, oily waste storage facilities, containers, and bulk pads.

2. Provision of surface water run-on and run-off control systems. The surface water run-off control system must be able to accommodate the volume of water from a 1 in 10 year, 24-hour storm. Collected surface run-off water can be:

   (a) used in the facility process if a water diversion permit is obtained from the Water Resources Division of AEP,

   (b) surface discharged provided it is field tested and meets the following criteria prior to being released, in a controlled fashion, to adjacent lands:

      i) chloride content: 500 mg/L maximum (i.e. test strips),
      ii) pH: 6.0 to 9.0, (i.e. test strips and/or meter readings),
      iii) no visible hydrocarbon sheen,
      iv) no other chemical contamination,
      v) landowner consent,
      vi) water must not be able to flow directly into any watercourse, and
      vii) each release must be recorded including the pre-release test data and the estimated volume of water released, or

   (c) deep well disposed.

3. Provisions to control odours during receiving, processing, treating, and disposing of waste materials. If the facility is approved to handle sour fluids, extra precautions must be in place to ensure that odours are controlled.

4. Acceptance of only characterized materials that the facility's process is capable of handling. This may involve analyzing the waste materials prior to acceptance. Licensees and/or approval holders should implement a quality control/quality assurance program to verify composition of incoming waste materials.

5. Development of a waste management plan for the handling and disposing of residuals (i.e. solids and liquids) resulting from the process. Licensees and/or approval holders must ensure that residuals are characterized, and appropriate disposal methods/options are selected based on the characterization.

11.7 Site Assessment and Groundwater Protection

Certain oilfield waste management facilities will be required to have in place a monitoring system that will provide an early indication of potential groundwater impact. This may involve implementation of a comprehensive groundwater monitoring program for the site.

The waste management or disposal methods described in the following sections will indicate if groundwater monitoring is required for that specific method. When it is required, background data shall be submitted to the EUB as part of the application for approval of the facility. Once established, the groundwater monitoring system shall be sampled twice per year and the results must then be compiled into an annual report. Refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection.*

11.8 Record Keeping

The approval holder of an oilfield waste management facility shall:

1. retain copies of all dockets for materials received and shipped for a minimum of 2 years,

2. where applicable, retain groundwater and leachate monitoring information for a minimum of 5 years, and

3. keep copies of approvals at each facility.

11.9 Closure

It is expected that with good operating practices, the site on which an oilfield waste management facility is situated will be capable of being reclaimed to conditions suitable for the next intended land use. The EUB IL 96-3, *Suspension and Reclamation of Upstream Oil and Gas Facilities*, introduces a Memorandum of Understanding (MOU) that outlines an agreement reached between AEP and the EUB on these activities.

As per the MOU, all decontamination and land reclamation activities, regardless of whether the sites are active or inactive, are the regulatory responsibility of AEP. If contamination has occurred, licensees and/or approval holders are required to contact AEP directly to determine if further delineation or remediation is required. Licensees and/or approval holders must consult with AEP regarding appropriate remediation criteria and any in situ remediation work. Any materials excavated during remediation activities (i.e. contaminated soil) must be treated and/or disposed in a manner that is satisfactory to AEP. It is expected that this document will be used as a basis for storage, treatment, and disposal of the contaminated material. Options that are available include on-site treatment, sending the material to an AEP or EUB approved waste facility, or any other treatment/disposal method as directed or approved by AEP.

At the time of closure of either part or the whole facility, all inventories must be eliminated, surface equipment and structures must be dismantled, and if applicable, pipelines and wells must be properly abandoned. Complete closure of an oilfield waste management facility, as a minimum, shall involve:

1. elimination of the inventory,

2. dismantling of the structures and equipment,

3. abandoning wells or pipelines in accordance with EUB requirements,

4. conducting a detailed site assessment which shall clearly identify potential sources, nature and extent of any contamination,

5. implementation of a reclamation program that will render the site compatible with the next intended land use,

6. implementation of a post closure monitoring program, if necessary, and

7. documentation of the work undertaken, including independent verification to ensure that the reclamation objectives were achieved.

Prior to implementation of the reclamation program, companies need to consult with AEP regarding remediation objectives for the site.

It is expected that waste management components constructed on EUB approved oil and gas or oil sands facilities will be closed along with the production facilities or in some situations, when the sites are going through partial closure. Therefore, with the exception of fixed incinerators that require an approval and landfills, financial assurance will not be required for waste management components integrated into EUB approved production facilities.

The application process for an oilfield waste management facility which is to be constructed and operated on a stand-alone site, requires the applicant to submit a plan detailing how both planned or unplanned closure of the facility or any part of it, at any point during its active life would be performed. If the application is approved, the company will be required to post financial security to cover the cost of planned or unplanned closure (refer to Section 20.0, *Financial Security*).

12.0 Waste Storage Areas/Facilities and Waste Transfer Stations

12.1 Introduction

The **purpose** of this section is to identify the requirements for the storage of oilfield wastes at either an operating production facility or at a stand-alone facility that is dedicated to the storage of oilfield wastes.

Oilfield wastes, whether dangerous or non-dangerous, are generally stored in one of three locations:

- in a storage area on an EUB approved oil and gas or oil sands facility,
- at a waste storage facility (stand-alone site) operated by an oil and gas company for collection of their own wastes, or
- at a waste transfer station operated by an independent company as a third party waste receiver.

Filter and container crushing, as well as liquid removal by gravity settling can be performed at a storage area or facility, or at a waste transfer station. However, if there is any additional waste treatment being performed, then the facility is referred to as a waste processing facility and the requirements of Section 14.0, *Waste Processing Facilities*, apply.

Waste treatment means to apply any method, technique or process, including, without limitation, neutralization and stabilization, that is designed to change the physical, chemical, or biological character or composition of a substance.

Operating approvals are required for storage facilities and transfer stations. A storage area on an EUB approved oil and gas or oil sands facility would be included under the facility approval. The application requirements to obtain an approval for storage facilities, transfer stations, and waste processing facilities are contained in Part E.

12.2 Storage Areas

Waste storage areas are defined as sites on existing EUB approved oil and gas or oil sands facilities used for the purpose of collecting oilfield wastes or oily wastes from one or more of a company's facilities. The licensee and/or approval holder of the facility on which the storage area is located must be the same as that of the facilities from which the collected wastes are generated.

The storage areas must meet the requirements of EUB ID 95-03 and the accompanying Guide G-55, *Storage Requirements for the Upstream Petroleum Industry*.

Licensees and/or approval holders constructing a storage area on an existing EUB approved production facility must, as outlined in EUB Guide G-55, submit written notification to the local EUB Field office. Licensees and/or approval holders who intend to integrate a storage area with a new production facility shall include the following information in the facility application:

- design of the storage area,
- type(s) and volume(s) of stored materials,
- duration of storage, and
- final disposal/treatment methods of the stored waste materials.

12.3 Waste Storage Facilities and Transfer Stations

A stand-alone facility, which has been constructed for the purpose of collecting and storing oilfield wastes until volumes are sufficient for economic transfer to treatment and disposal facilities, is considered either a storage facility or a transfer station.

A waste storage facility is considered a first party receiver (i.e. receives only those wastes generated by one oil and gas company, but can come from various sites). The licensee or approval holder of the storage facility must be the same as that of the facilities from which the wastes are collected. **A waste transfer station** is considered a third party receiver (i.e. receives wastes generated by various companies and from various sites).

Waste storage facilities and transfer stations shall comply with the requirements (siting, safety, waste characterization, EIA, design and operation, record keeping, and closure) outlined in Section 11.0, *Oilfield Waste Management Facilities*.

If dangerous oilfield wastes are being stored, a comprehensive groundwater monitoring program must also be implemented. Refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection.*

12.4 Reporting and Record Keeping

In addition to the record keeping requirements outlined in Section 11.8, *Record Keeping* the following requirements also apply:

1. Monthly Documentation

Operators of waste storage facilities and waste transfer stations must document the following information and retain it on-site for a minimum of 2 years. The following information must be made available to EUB staff upon request:

(a) a balance of opening inventory for each month,

(b) for each receipt of waste material, the volume, source, generator, type (characterization), and date received, and

(c) a closing inventory balance for each month identifying total volumes of waste materials received, volumes of waste materials sent for treatment and/or disposal, and the name and location of the treatment and/or disposal facility.

2. Annual Report

Licensees and/or approval holders of **waste transfer stations** must summarize the monthly information and prepare an annual report by the 31 March of each year. This report, which must be retained on site for a minimum of 2 years and be made available to EUB staff upon request, shall contain as a minimum:

(a) monthly totals of each waste type received,

(b) monthly totals of each waste type sent for treatment and/or disposal, and the name and location of the treatment and/or disposal facility, and

(c) a summary of the results of groundwater monitoring (if any).

13.0 Surface Facilities Associated with Disposal Wells

13.1 Introduction

The purpose of this section is to outline environmentally sound operating practices and principles for surface facilities that receive upstream oilfield wastes prior to deep well injection and are not covered under an existing EUB facility approval.

The deep well disposal of oilfield waste fluids involves the regulatory requirements for both the disposal well and the surface facility that is associated with the disposal well. Surface facilities include above ground tanks, underground tanks, and any container or group of containers with an aggregate volume larger than 1 cubic metre, as well as associated piping, processing equipment, and pumps.

Requirements for the disposal wells are contained in EUB IL 94-2, Guide G-51, *Injection and Disposal Wells, Well Classifications, Completion, Logging, and Testing Requirements*.

Specific disposal well regulations are contained in the Oil and Gas Conservation Regulations Sections 8.040 (water disposal requirements) and 15.070 (application requirements).

Surface facilities used for the receipt of industrial wastes (i.e. downstream wastes such as those generated at refineries or petrochemical plants) prior to deep well injection, as well as the waste streams being disposed down the well, must be approved by AEP. The plan to manage any residuals (solids or organics) that separate from the industrial wastes fluids within the surface facilities (tanks) must also be approved by AEP.

The requirements for the surface facilities used for the receipt of upstream oilfield wastes prior to injection down waste disposal wells are addressed in this section.

An approval for a surface facility associated with a waste disposal well is required when:

- the disposal well is a stand alone Class Ia or Ib well, or
- the surface facilities associated with the well are not covered by an EUB facility approval.

Disposal wells tied into a pipeline originating from an approved waste processing facility will not require a surface facilities approval, provided there is no additional tankage at the well site. The application for approval of surface facilities associated with a waste disposal well can be made in conjunction with the disposal well application.

Class Ia wells can be approved for the disposal of oilfield and/or industrial fluids. Class Ib wells are typically approved for the disposal of produced water, specific common oilfield waste streams, and waste streams meeting specific criteria as outlined in Guide G-51.

Any solid or organic fractions that separate from the waste fluids within the surface facilities (tanks) associated with disposal wells must be treated and/or disposed of appropriately.

13.2 General Requirements

Surface facilities that receive upstream oilfield wastes and are associated with waste disposal wells, and are not covered under existing EUB facility approval, shall comply with the requirements (siting, safety, waste characterization, design and operation, record keeping, and closure) outlined in Section 11.0, *Oilfield Waste Management Facilitities*.

13.3 Groundwater Monitoring

Surface facilities associated with a Class Ia well, must have a comprehensive groundwater monitoring program in place. Refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection*.

13.4 Class Ia Wells Accepting Upstream and Downstream Fluids

Class Ia wells which receive fluids generated within the upstream petroleum industry as well as waste fluids generated within other industries (downstream), must segregate the upstream fluids from the industrial fluids. The surface facilities used for the receipt of industrial wastes, the industrial waste streams, and the plans to manage any residuals must be approved by AEP.

Skim oil from the upstream tanks may enter the crude oil stream provided it is sent to an approved oilfield waste processing facility for treatment prior to entering the pipeline for sales, or the protocol outlined in Section 31.0, *Waste Transport by Pipelines* is followed. Any tank bottoms must be sent to an EUB or AEP approved facility for treatment and/or disposal.

13.5 Reporting and Record Keeping

In addition to the record keeping requirements outlined in Section 11.8, *Record Keeping* the following requirements also apply.

The S-18 form, *Monthly Injection/Disposal Statement,* shall be used to report the source, volume, and type of all wastes disposed by deep well injection, for both Class Ia and Class Ib wells. Any recovered crude oil must also be reported.

14.0 Waste Processing Facilities

14.1 Introduction

The **purpose** of this section is to provide minimum requirements for the design and operation of an oilfield waste processing facility.

Waste processing means to apply any method, technique, or process that is designed to change the physical, chemical, or biological character or composition of a substance.

A waste processing facility is defined as a system of surface equipment designed for the purpose of collecting and treating oilfield waste material from any gas, oil, oilfield, or oil sands operation.

The techniques or methods applied by facilities designed specifically for the recovery of crude oil often include a combination of retention time, gravity separation, heat application, chemical application, mechanical mixing, centrifuging, and water washing.

A cavern is typically approved as a disposal well. In cases where waste streams are injected into the cavern for purposes of separation and oil recovery, it will also require approval as a waste processing facility.

Other waste processing facilities include those designed to collect oilfield waste and apply methods or techniques to reduce volumes, alter chemical characteristics, and/or remove dangerous components prior to final disposal.

Waste processing facilities accepting wastes generated within the upstream petroleum industry only require approval from the EUB. Facilities that accept a combination of upstream and downstream waste or industrial waste only require approval from AEP and do not require EUB approval.

14.2 General Requirements

All oilfield waste processing facilities shall comply with the requirements (siting, safety, waste characterization, EIA, design and operation, site assessment and groundwater protection, record keeping, and closure) outlined in Section 11.0, *Oilfield Waste Management Facilities*.

14.3 Groundwater Monitoring

Licensees and/or approval holders of oilfield waste processing facilities must implement a comprehensive groundwater monitoring program for their site (refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection*).

14.4 Reporting and Record Keeping

In addition to the record keeping requirements outlined in Section 11.8, *Record Keeping*, the following requirements also apply.

The operator of a waste processing facility will be required by the approval to operate, to submit a S-25 form, *Monthly Waste Plant Statement*. This report as a minimum shall include:

1. an opening monthly inventory balance of wastes, residuals (liquids and solids), and/or products (recovered crude oil),

2. type, volume, origin, generator of each receipt of waste material,

3. the volume and deliveries (name and location of facility) of residuals and/or recovered crude oil, and

4. a closing monthly inventory balance of wastes, residuals (liquids and solids), and/or products (recovered crude oil).

15.0 Oilfield Landfills

15.1 Introduction

The purpose of this section is to establish the minimum requirements for the design and operation of oilfield landfills, and to identify the types of non-EUB regulated landfills which may accept oilfield waste.

Oilfield landfills are:

- operated by an oil and gas company for the purpose of disposing of oilfield wastes produced from their own operations,
- operated as part of an oilfield waste processing facility for the purpose of disposing of residual wastes resulting from their treatment process, or
- operated by an independent company for the purpose of disposing of third party waste generated by the upstream petroleum industry.

An oilfield landfill shall not receive municipal, non-upstream petroleum nor other industrial wastes. All oilfield landfills, including those to be integrated into an EUB approved production facility, require approval from the EUB to construct or expand. The application requirements to obtain the approval are contained in Section 21.0, *General Information Required in Applications,* and Section 25.0, *Oilfield Landfills - Specific Application Information.*

15.2 AEP Regulated Landfills Versus Oilfield Landfills

The Government of Alberta recently approved the transfer of regulatory responsibility for municipal waste management facilities from the Public Health Act to the Environmental Protection and Enhancement Act (EPEA). AEP's Code of Practice for Landfills establishes the requirements for Class II and Class III landfills receiving less than 10 000 tonnes of waste per year, and will form the basis for approvals for larger landfills.

In order for there to be a consistent approach toward the design of landfills and the landfilling of waste in Alberta, EUB oilfield landfill requirements are consistent with the Waste Control Regulation of EPEA and AEP's Code of Practice for landfills.

15.3 Disposal of Oilfield Waste at AEP Regulated Landfills

The disposal of oilfield waste at AEP regulated landfills, which are designed primarily for other sources or types of waste, such as municipal waste, may not be an effective use of that landfill's capacity, and may represent a potential environmental problem depending on the specific characteristics of the waste.

If a waste generator wishes to dispose of their oilfield waste at a landfill which is not under the jurisdiction of the EUB, the onus is placed on the waste generator to ensure that the destination landfill is of appropriate design and is approved to accept the type of waste in question (refer to Subsection 15.8, *Waste Criteria* and Section 2.1, *Responsibilities*).

The disposal of any liquid oilfield waste in landfills is prohibited.

Dangerous oilfield waste shall only be deposited in appropriately designed EUB approved oilfield landfills, or AEP regulated landfills which are approved to accept hazardous waste.

15.4 General Requirements for Oilfield Landfills

All oilfield landfills shall comply with the general requirements in Section 11.0, *Oilfield Waste Management Facilities*.

15.5 Landfill Siting Criteria

In addition to the general siting criteria in Section 11.2 for all oilfield waste management facilities, the following criteria also apply:

1. Prior to construction or lateral expansion of a landfill, the approval holder shall ensure the following:

    (a) An investigation shall be designed and conducted by a professional geologist or engineer registered with the Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA) to assess the geological and hydrogeological conditions specific to the landfill and its surrounding area,

    (b) After an investigation is designed and conducted in accordance with Section 15.5(1)(a), a landfill design shall be prepared by a professional geologist or engineer registered with APEGGA, and the approval holder shall construct the landfill according to the design,

    (c) The approval holder shall conduct a soil survey to determine the depth and volume of topsoil and subsoil available at the landfill site, and

    (d) Prior to construction or lateral expansion of a landfill, the approval holder shall determine storage locations of salvaged topsoil, and measures to be taken to prevent the use or loss of salvaged topsoil during storage.

2. No person shall construct or operate an oilfield landfill within:

   (a) 300 m of the shore of a natural area that permanently contains water, such as a river, lake, or creek,

   (b) 300 m of the shore of a man-made surface feature that permanently contains water, such as an irrigation canal or drainage ditch, but not a roadside ditch, dugout, or reservoir,

   (c) wetlands, critical wildlife habitats, or areas immediately adjacent, where the natural drainage from the landfill would flow directly onto the wetland or critical wildlife area,

   (d) 100 m of any land subject to slope failure which would compromise the landfill's structural integrity, or any other land with similar unsuitable characteristics, or

   (e) 300 m of the perimeter of a wellhead protection zone of a municipal or community water supply.

3. The topography in the immediate vicinity of the landfill site shall be level to gently rolling. Terrain with steep slopes, ravines, gullies and coulees, low-lying areas, flood plains and lake shores are unsuitable.

4. The approval holder shall ensure that no waste is deposited within 100 m of a highway, railroad right-of-way, municipal road, or street.

5. The following geological and hydrogeological criteria shall be applied when choosing a site for an oilfield landfill. The site shall not be within:

   (a) 30 m vertically of an aquifer,

      (i) capable of yielding water meeting domestic use quality standards, and
      (ii) having a transmissivity of 5×10^{-4} m^2/sec or greater,

   (b) 10 m vertically of fractured bedrock, or

   (c) a recharge area of an unconfined aquifer.

6. The bottom of a landfill trench or cell shall be at least 1.5 m above the seasonal high water table.

15.6 Design and Operation

Oilfield landfills are divided into four classes (Class Ia, Ib, II, and III). Design Requirements and Operating Procedures apply to all classes of oilfield landfills. The specific waste streams that may be disposed in each class of landfill are outlined in Section 15.8, *Waste Criteria.*

Approval holders are cautioned that if they intend to construct a new oilfield landfill to accept dangerous oilfield waste, it should be designed to comply with Class Ia criteria.

1. Design Requirements

In addition to the design and operation requirements listed in Section 11.6 for all waste management facilities, the following requirements also apply:

(a) Reclamation design and the proposed post reclamation use of the landfill site must be incorporated into the overall design of the landfill, starting at the initial site assessment phase.

(b) A comprehensive groundwater monitoring program (see Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection*) must be included in the design, operation, and decommissioning of an oilfield landfill. Data reflecting background conditions must be obtained prior to commencement of operation. Groundwater monitoring during the operational life of the landfill, as well as after closure of the landfill, must provide sufficient information to assess and quantify potential impact on the surrounding groundwater. Evidence of adverse impact shall result in implementation of remedial action.

(c) During the construction phase of the landfill, the approval holder may be required to provide evidence that exhibits compliance with the proposed design criteria. The evidence may be in the form of engineering and geological studies, survey plots, technical data, or other means.

(d) A financial assurance program is required for the life of the landfill, including post closure reclamation (see Section 20.0, *Financial Security*).

2. Operating Procedures

(a) The approval holder shall develop, maintain, and implement an operations plan that ensures landfill operations are consistent with the design and includes as a minimum:

(i) operational procedures such as waste control, soil cover operations, surface water management, and nuisance controls,

(ii) waste acceptance procedures and policies,

(iii) an emergency response program covering fires, releases, and medical concerns, and

(iv) for Class Ia, Ib, and II landfills, a remediation program to be implemented if groundwater quality fails to meet performance standards set out in Section 15.6(2)(j).

(b) Incompatible wastes shall be disposed in a manner that does not create hazardous conditions.

(c) Approval holders of Class Ia, Ib, and II landfills shall cover wastes with at least 15 cm of soil, or an alternative cover material approved by the EUB, to control litter, prevent spread of fires, minimize propagation of disease vectors, reduce odours, and minimize infiltration of moisture. Waste shall be covered within at least:

(i) 30 days from the last cover operation at landfills that receive less than 1 000 tonnes of waste per year,

(ii) 15 days from the last cover operation at landfills that receive between 1 000 and 3 000 tonnes of waste per year,

(iii) 7 days from the last cover operation at landfills that receive between 3 000 and 5 000 tonnes of waste per year, and

(iv) 48 hours from the last cover operation at landfills that receive between 5 000 and 10 000 tonnes of waste per year.

(d) If soil is used as cover material, the approval holder is not required to apply the required soil cover during the period between 15 November and 15 April, if the necessary soil cover material cannot reasonably be obtained.

(e) The EUB may require increased frequency of cover, where deemed necessary.

(f) The approval holder for a Class III landfill shall cover wastes as necessary to control nuisances such as litter, fires, disease vectors, odors, and dust.

(g) The landfill shall be operated to minimize production of leachate, and prevent the uncontrolled release of leachate from the site.

(h) Water that accumulates in a landfill trench shall be removed to avoid contact with the waste.

(i) Leachate, contaminated surface water, and contaminated groundwater shall be treated and appropriately disposed.

(j) Throughout the active life and post-closure period of a Class Ia, Ib, or II landfill, the approval holder shall ensure that the groundwater quality meets the performance standards listed in Table 15.1 in the uppermost formation(s) at all groundwater monitoring wells.

Table 15.1

Performance Standards for Landfills

Parameter	Concentration or Level
Total dissolved solids	2 000 mg/L
Chloride	250 mg/L
Sodium	200 mg/L
Sulphate	500 mg/L
Electrical Conductivity	2 dS/m
Total Metals	CCME Interim Assessment Criteria for Water
Mineral Oil and Grease	site-specific
pH	6.5 to 8.5 units

(k) The approval holder shall ensure that each groundwater monitoring well location includes one groundwater monitoring well designed to allow collection of groundwater samples from the uppermost formation(s).

(l) The EUB may require the approval holder to construct and maintain additional groundwater monitoring wells at each groundwater monitoring well location, if there is more than one significant uppermost formation underlying the landfill site.

(m) The EUB may require the approval holder to construct and maintain additional groundwater monitoring wells, if it is deemed necessary due to the size, area, or hydrogeology of the landfill, or the nature of the waste proposed to be accepted at the landfill.

(n) The groundwater monitoring wells for a Class II landfill shall be:

(i) at least 20 m inside the property boundary, and

(ii) at least 10 m but not more than 60 m from the designed boundary of the landfill.

(o) During construction and operation of a landfill, the approval holder shall selectively salvage and stockpile all topsoil as follows:

(i) all topsoil stockpiles shall be located on undisturbed topsoil in a location that is not affected by the landfill operations,

(ii) topsoil shall not be used to meet daily cover requirements, and

(iii) all topsoil stockpiles shall be contoured, stabilized, and seeded to prevent soil loss by wind and water erosion.

(p) A system must be in place to measure quantities of waste being placed in the oilfield landfill. Weigh scales are one method (refer to Section 15.10(1), *Annual Reports*).

(q) Approval holders of oilfield landfills shall institute a program for detecting and preventing the disposal of dangerous wastes at Class II or Class III landfills. Approval holders of Class III landfills shall institute a program for detecting and preventing the disposal of dangerous oilfield wastes and non-inert wastes at the landfill. For example, by:

- randomly inspecting incoming loads to ensure that they do not contain wastes that are not authorized for the landfill, and by maintaining records of these random inspections at the landfill, and.
- Continuous supervision of all off-loading operations and training landfill personnel to recognize potentially dangerous oilfield wastes.

(r) Burning of wastes at oilfield landfills is prohibited.

(s) The approval holder shall post signs at the landfill boundary providing the following information:

(i) the name of the approval holder,

(ii) the landfill class,

(iii) any waste restrictions, and

(iv) telephone numbers for:

- the approval holder,
- the local fire department,
- Alberta Environmental Protection, Pollution Emergency Response Team (1-800-222-6514)
- applicable EUB Field Centre address and phone number, and
- the local police department.

(t) The approval holder shall ensure that fires are extinguished immediately upon detection.

(u) The approval holder shall establish and maintain litter controls to minimize the escape of litter and shall retrieve litter that is washed or blown onto adjacent properties or accumulates on the landfill site.

(v) The approval holder shall use artificial or natural barriers to control public access to the landfill and prevent unauthorized vehicular traffic and illegal dumping of wastes.

(w) The approval holder shall ensure that no waste is deposited between the property line and the designated boundary of the landfill.

(x) The approval holder must notify the EUB immediately in writing if dangerous oilfield waste is discovered at a Class II landfill, or if dangerous oilfield waste or non-inert waste is discovered at a Class III oilfield landfill.

15.7 Oilfield Landfill Classes

1. Class Ia Oilfield Landfill

This class of oilfield landfill can accept solid oilfield waste, both dangerous and non-dangerous, provided that the waste criteria in Section 15.8 are met. A Class Ia oilfield landfill shall include, as a minimum, the following engineered features:

(a) Two liners of which at least one is a geo-synthetic liner. The liner used for primary containment must be compatible with all potentially accepted waste types, and must exhibit hydraulic conductivity of 1×10^{-8} m/sec or less. Liners used for secondary containment must be compatible with all potentially accepted waste types and must exhibit hydraulic conductivity of 1 x 10^{-8} m/sec or less. An engineered compacted clay liner, if used as secondary containment, shall have a minimum thickness of 0.5 m.

(b) The approval holder shall ensure that the natural geologic materials surrounding the secondary containment, together with the local hydrogeologic flow regime shall be sufficient to retard the movement of any potential containments.

(c) A leachate collection and removal system above the primary liner.

(d) A leak detection system between the two liners.

(e) A run-on control system to prevent flow onto the active portion of the landfill for events up to at least the peak discharge from the larger of a 1 in 25-year storm or snow melt event.

(f) A run-off control system for the active portion of the landfill to collect and control at least the run-off water volume resulting from the larger of a 1 in 25-year storm or snow melt event.

(g) A site specific groundwater monitoring system consisting of groundwater monitoring wells located in areas hydraulically upgradient and downgradient of the landfill. The completion of the observation wells shall be at adequate depths to provide an indication of the impact of the landfill on water-bearing zones.

(h) The landfill shall be developed and managed to prevent the production of leachate by minimizing the amount of moisture that enters the waste fill.

(i) A suitable gas detection, interception, and venting or recovery system, where gas generation is expected, so that all emissions meet AEP Ambient Air Quality Guidelines.

2. Class Ib Oilfield Landfill

This class of oilfield landfill can accept solid oilfield waste, both dangerous and non-dangerous, provided that the waste criteria in Section 15.8 are met. A Class Ib oilfield landfill shall include, as a minimum, the following engineered features:

(a) Primary containment consisting of a geosynthetic or engineered, compacted clay liner which is compatible with all potentially accepted wastes, and has a hydraulic conductivity of 1 x 10^{-8} m/sec or less.

(b) The approval holder shall ensure that natural geologic materials surrounding the primary containment, together with the local hydrogeolgic flow regime, shall be sufficient to retard the movement of any potential containments.

(c) A leachate collection and removal system above the primary liner.

(d) A run-on control system to prevent flow onto the active portion of the landfill for events up to at least the peak discharge from the larger of a 1 in 25-year storm or snow melt event.

(e) A run-off control system for the active portion of the landfill to collect and control at least the run-off water volume resulting from the larger of a 1 in 25-year storm or snow melt event.

(f) A site specfic groundwater monitoring system consisting of groundwater monitoring wells located in areas hydraulically upgradient and downgradient of the landfill. The completion of the observation wells shall be at adequate depths to provide an indication of the impact of the landfill on water-bearing zones.

(g) The landfill shall be developed and managed to prevent the production of leachate by minimizing the amount of moisture that enters the waste fill.

(h) A suitable gas detection, interception, and venting or recovery system, where gas generation is expected, so that all emissions meet AEP Ambient Air Quality Guidelines.

3. Class II Oilfield Landfill

This class of oilfield landfill can accept only non-dangerous solid oilfield waste. A Class II oilfield landfill shall include, as a minimum, the following engineered features:

(a) Primary containment consisting of a geosynthetic or engineered, compacted clay liner which is compatible with all potentially accepted wastes, and has a hydraulic conductivity of 1 x 10^{-8} m/sec or less, and a leachate collection and removal system.

(b) A run-on control system to prevent flow onto the active portion of the landfill for events up to at least the peak discharge from the larger of a 1 in 25-year storm or snow melt event.

(c) A run-off control system for the active portion of the landfill to collect and control at least the run-off water volume resulting from the larger of a 1 in 25-year storm or snow melt event.

(d) A groundwater monitoring system consisting of at least one groundwater monitoring well location hydraulically upgradient from the landfill, and two groundwater monitoring well locations hydraulically downgradient from the landfill. The completion of the observation wells shall be at adequate depths to provide an indication of the impact of the landfill on water-bearing zones.

(e) The landfill shall be developed and managed to prevent the production of leachate by minimizing the amount of moisture that enters the waste fill.

(f) A suitable gas detection, interception, and venting or recovery system, where gas generation is expected, so that all emissions meet AEP Ambient Air Quality Guidelines.

(g) An approval holder constructing or expanding a Class II landfill may develop a landfill design with an alternate feature to that required in Section 15.7(3)(a) if:

(i) the following hydrogeological conditions are met:

- there is a 5 m thick layer of a clayey deposit having a hydraulic conductivity less than 1 x 10^{-8} m/sec immediately beneath all waste disposed at or below the original grade, and

- the hydraulic conductivity of the natural geologic materials beneath the clayey deposit is less than 1 x 10^{-8} m/sec to a depth of at least 6 m beneath the clayey deposit or provides equivalent protection, or

(ii) the approval holder provides evidence in writing to the EUB that groundwater quality will not exceed the performance standards set out in Table 15.1 at all groundwater monitoring wells.

4. Class III Oilfield Landfill

This class of oilfield landfill can accept only non-dangerous, chemically inert and non-leachable, solid oilfield wastes. Examples include demolition debris, concrete, asphalt, glass, cement returns, scrap metal, brush and non-chemically treated dry timber or wood. A Class III oilfield landfill shall include as a minimum, the following features:

(a) Construction that provides for containment of the waste disposed.

(b) a run-on control system to prevent flow onto the active portion of the landfill for events up to at least the peak discharge from the larger of a 1 in 25-year storm or snow melt event.

(c) A run-off control system for the active portion of the landfill to collect and control at least the run-off water volume resulting from the larger of a 1 in 25-year storm or snow melt event;

(d) Materials should be crushed, chipped, or otherwise broken into small pieces to facilitate compaction.

(e) Groundwater monitoring may be required, where deemed necessary by the EUB.

15.8 Waste Criteria

1. Waste Deposition Limitations

(a) Landfilling of liquid oilfield wastes is prohibited,

(b) Oilfield wastes may be deposited in landfills approved by AEP, such as landfills commonly described as municipal, regional, or industrial landfills, provided that the landfill has design criteria appropriate for the oilfield wastes being disposed,

(c) It is the responsibility of the waste generator to determine the characteristics of the waste. Based on that information, and the corresponding landfill design characteristics specified in Sections 15.6 and 15.7, the waste generator must then determine which class of oilfield landfill or AEP approved landfill has the appropriate design criteria for that type of waste, and

(d) Solid dangerous oilfield wastes shall only be deposited in an approved Class Ia or Ib Oilfield Landfill, or an AEP regulated landfill which is approved to accept hazardous wastes.

2. Dangerous Oilfield Wastes

Only the following types of dangerous oilfield waste may be disposed in Class Ia or Class Ib oilfield landfills, or AEP regulated landfills which are approved to accept hazardous waste, as outlined in Section 15.6, *Oilfield Landfill Classes*.

(a) Solid dangerous oilfield waste containing one or more halogenated organic compounds in a combined concentration less than 1 000 milligrams per kilogram (mg/kg) of which no more than 50 mg/kg is polychlorinated biphenyl; or

(b) Solid dangerous oilfield waste containing one or more of the following compounds in a combined concentration **less** than 1 000 mg/kg:

- acetone,
- benzene,
- n-butyl alcohol,
- carbon disulphide,
- cresol and cresylic acid,
- cyclohexanone,
- ethyl acetate,
- ethyl benzene,
- ethyl ether,
- isobutanol,
- methanol,
- methyl ethyl ketone,
- nitrobenzene,
- 2-nitropropane,
- pyridine,
- toluene,
- xylene, or

(c) dangerous oilfield waste with a pH greater than 12.5, or

(d) Any substance or mixture of substances that ignites and propagates combustion according to the test methods that describe spontaneously combustible dangerous wastes, provided that those substances or mixtures of substances are not liable to ignite and propagate combustion under the conditions of disposal, and are not liable to emit flammable gases under the conditions of disposal, or

(e) Solid dangerous oilfield waste producing a waste extract which contains one or more of the following substances in a concentration **less** than the value for that substance shown below:

-	arsenic	500 mg/kg,
-	beryllium	100 mg/kg,
-	cadmium	100 mg/kg,
-	chromium (Cr^{6+})	500 mg/kg,
-	lead	500 mg/kg,
-	mercury	20 mg/kg,
-	nickel	500 mg/kg,
-	selenium	200 mg/kg,
-	silver	100 mg/kg,
-	thallium	200 mg/kg.

15.9 Monitoring and Analysis

1. The approval holder shall conduct groundwater monitoring on a semi-annual basis as required by the EUB throughout the active life, and by AEP throughout the post-closure period of the landfill. The approval holder shall analyze the samples for the parameters set out in Section 15.6(2)(j). The post-closure period of a landfill is defined as the period of 25 years from the final closure of a landfill, or as long as leachate that does not meet the performance standards for landfills (listed in Table 15.1), is generated at a landfill after final closure.

2. The EUB may:

   (a) require that groundwater samples be analyzed for parameters other than those set out in Section 15.6(2)(j),

   (b) change the frequency of groundwater monitoring and analysis required under section 15.9(1), or

   (c) require the approval holder to install additional groundwater monitoring wells where it is deemed necessary due to the characteristics of waste received at the landfill, changes in groundwater quality at the landfill, or other evidence that suggests an impact on groundwater quality.

3. Where groundwater at the landfill fails to meet the performance standards set out in Section 15.6(2)(j), the approval holder shall notify the EUB and shall implement the groundwater remediation plan developed under Section 15.6(2)(a)(iv).

4. Where groundwater monitoring is required, the approval holder shall:

   (a) ensure that all groundwater monitoring wells are protected from damage and are locked except when being sampled, and

   (b) clean, repair, or replace groundwater monitoring wells, which have been damaged or are no longer able to produce representative groundwater samples, prior to the next scheduled sampling date.

5. The approval holder shall conduct analyses of samples collected to meet these requirements in the following manner:

   (a) for water and leachate samples, in accordance with the recommended test methods listed in Appendix 3.0, and

   (b) for solid wastes samples, in accordance with the recommended test methods listed in Appendix 3.0.

15.10 Reporting Requirements

1. Annual Reports

The approval holder of an oilfield landfill will be required by the approval to operate, to prepare by 31 March of each year, a report containing the following items and to make it available to EUB staff upon request:

(a) the type and volume of each major waste stream that was placed in the landfill, and the locations of disposal of wastes requiring special handling,

(b) the groundwater monitoring data pursuant to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection,*

(c) survey records and as-built records for the landfill showing the location and development of excavations, fill areas, final grades and structural components,

(d) the current version of design and operation plans for the landfill,

(e) records of random inspections carried out under Section 15.6(2)(q),

(f) records of personnel training carried out under Section 15.6(2)(q),

(g) copies of any notices given to the EUB under Section 15.6(2)(x) regarding hazardous or non-inert waste,

(h) results of gas monitoring,

(i) records of the quality of surface water released to the environment,

(j) volumes of leachate generated, if any, characterization of the leachate and the method of disposal,

(k) an interpretation of the requested data which should include identification of any change in the quality of the groundwater, and

(l) a remedial plan to correct any changes identified in (k) above. Enforcement action may result if remedial action has not been instituted in a timely fashion.

2. Record Keeping

In addition to the record keeping requirements outlined in Section 11.8, the approval holder shall maintain the following records until the end of the post-closure period:

(a) waste generator identification, type of major waste stream, volume, and approximate location where the material was landfilled, and

(b) initial site assessment groundwater sample data.

3. Closure, Post-Closure, and Reclamation Requirements

The reclamation plan, as laid out during the initial design of the landfill, is to be incorporated throughout the operational life of the landfill. Prior to final closure of the landfill, the approval holder shall notify the EUB in writing of the intent to close the landfill. The approval holder shall begin closure no later than 180 days after the landfill or trench reaches its final design elevation, and complete closure no later than 180 days after the beginning of closure.

The post-closure period of a landfill is defined as the period of 25 years from the final closure of a landfill, or as long as leachate that does not meet the performance standards for landfills (listed in Table 15.1) is generated at a landfill after final closure.

Upon final closure of landfills, the jurisdiction transfers to AEP for post-closure and reclamation requirements. Upon final closure of the landfill, the following components must be included, and/or any other requirements deemed necessary by AEP:

(a) The approval holder must maintain records of the type of materials buried on-site, and the burial location and depth. These records shall be made available to AEP staff upon request.

(b) All monitoring and analysis data shall be made available to AEP staff on request.

(c) The closure and reclamation plan, which is laid out during the initial design of the landfill and submitted as part of the original application, shall be completed and include the following information:

  (i) a description of the proposed final cover system, and the installation methods, and procedures,

  (ii) an estimate of the maximum quantity of wastes on-site over the active life of the landfill,

(iii) a description of how the following elements have been or will be dealt with:

- the final use of the reclaimed areas,
- drainage restoration,
- soil replacement,
- final cover slopes,
- erosion control,
- revegetation and conditioning of the site, and
- subsidence remediation.

(iv) a schedule for completing closure and reclamation, and

(v) a detailed landfill site assessment which shall clearly identify landfill impacts, nature, and extent of any contamination.

(d) At closure of the landfill or any trench, the approval holder shall install a final cover system designed to and constructed to:

(i) provide long term minimization of migration of liquids through the closed landfill,

(ii) function with minimum maintenance,

(iii) minimize erosion or abrasion of the cover, and

(iv) accommodate settling and subsidence and be resistant to burrowing activity of animals and root penetration so that the cover's integrity is maintained.

(e) The approval holder shall ensure that the final cover system meets the following requirements, and shall construct the layers in the following order:

(i) the final cover system shall include a barrier layer of 0.6 m of a maximum permeability of 1×10^{-7} m/sec, or of alternate material that will achieve equivalent protection,

(ii) subsoil shall be placed as the second layer of the final cover system and salvaged topsoil as the third layer of the final cover system as follows:

- required subsoil shall be spread evenly over the barrier layer, and

- all salvaged topsoil shall be spread evenly over the replaced subsoil,

(iii) the depths of the replaced topsoil and subsoil shall be equal to the depths determined at the landfill site prior to its construction, or shall meet the following minimum requirements:

- for pasture or recreational uses, 0.20 m of topsoil and 0.35 m of subsoil, and

- for cultivated land use or forestry, 0.20 m of topsoil and 0.80 m of subsoil,

(iv) after the subsoil and topsoil are replaced,

- water permeability and rooting in topsoil or subsoil shall not be restricted, and

- vegetation shall be established with a suitable seed mixture compatible with the intended land use,

(v) the final cover system shall have a final topography that ensures that water does not pool over the landfill area with a minimum final grade of 5 per cent, and a maximum final grade of 30 per cent.

(f) Following final closure of the landfill, the approval holder shall notify the EUB in writing, verifying that:

(i) closure has been completed in accordance with the closure and reclamation plan and these requirements, and

(ii) the landfill area is compatible with the proposed end land use.

(g) After final closure of the landfill and during the post-closure period, the approval holder shall:

(i) maintain the integrity of the final cover system and diversion and drainage structures, and make repairs to the cover system as necessary to correct the effects of settling, subsidence, erosion, or other events,

(ii) maintain, operate, and monitor the groundwater monitoring, leak detection, leachate collection, and gas venting or recovery systems, where such systems or structures are installed,

(iii) protect and maintain surveyed benchmarks, and

(iv) anything else deemed necessary by AEP.

16.0 Biodegradation

16.1 Introduction

The **purpose** of this section is to establish minimum requirements for the design and operation of techniques and facilities used for the biodegradation of oilfield wastes.

These requirements will ensure that:

- effective waste treatment occurs rather than dilution,
- there is minimal potential for the transfer of contaminants to another medium, and
- extensive clean-up of the facility or treatment site will not be necessary at the time of closure.

The biodegradation techniques and facilities addressed by this document include:

- on-site land treatment of a single application of hydrocarbon contaminated soil or pit/pond sludge, and
- biocell/biopile treatment or facilities.

Land treatment, biopile, and biocell are techniques commonly used to aerobically biodegrade hydrocarbon contaminated soils and sludges. Biodegradation is a catabolic process conducted by soil residing microorganisms, in which hydrocarbon is used as a source of carbon to satisfy the microorganisms' energy and cellular growth needs.

As the process is microbiologically driven, the strategy for successful biodegradation involves optimizing conditions for microbial activity, such as temperature, pH, moisture, nutrient, and oxygen levels. In addition, the hydrocarbon must be biodegradable and not toxic to the microorganisms. Carbon dioxide, water, and non-toxic residue compounds are the expected products of the microbiological process.

As oilfield wastes can contain more than one type of contaminant, some of which may be poorly degradable or non-degradable, the potential for successful biodegradation of oilfield wastes varies. Within the upstream petroleum industry, hydrocarbon contaminated soils and sludges have been successfully biodegraded. Biodegradation success is typically greatest when the hydrocarbon contaminant consists of low molecular weight aromatics and aliphatics. Hydrocarbon contaminants containing a large fraction of asphaltenes or nitrogen and sulphur rich heterocyclic compounds may take a long time to degrade and may even produce toxic intermediates.

Sites receiving multiple applications of oilfield wastes are considered dedicated land treatment facilities, which in the past the EUB approved as a component or type of oilfield waste management facility. In late 1995 a task group was established to review and update the AEP document *Guidelines for Land Treatment of Industrial Waste*. The EUB is a member of this task group and during the interim, while these guidelines are being revised to reflect today's legislation, policy, and environmental science, the EUB will not accept, review, or approve any applications for new dedicated land treatment facilities. However, previously approved dedicated land treatment facilities will be allowed to continue to operate provided they are operated in accordance with their EUB approval. As well, during this interim period the EUB will not accept, review, or approve applications for the expansion of existing approved land treatment facilities.

16.2 On-Site Land Treatment of a Single Application of Non-Refined Hydrocarbon Contaminated Soil or Pit/Pond Sludge on an Active Oil and Gas Site

1. Introduction

Land treatment is defined as a planned and controlled mixing of the waste and surface soil in which the inherent soil processes are used to biodegrade, transform, and assimilate waste constituents. The oilfield wastes that are appropriate for this technique are limited to non-refined hydrocarbon contaminated soils resulting from spills/leaks and non-refined hydrocarbon contaminated pit/pond sludges. As previously described in section 11.9, all decontamination and land reclamation activities, regardless of whether the sites are active or inactive, are the regulatory responsibility of AEP. Approval holders and licensees must comply with the one-time-only land treatment protocol described in the following subsections unless otherwise directed or approved by AEP. Approval holders and licensees wanting to deviate from this protocol (i.e. use a risk approach or Tier II approach) must obtain approval from AEP.

Considerations for using land treatment include:

- The wastes must be susceptible to biodegradation in the soil environment, create no offensive odours at the site boundaries, and not pollute groundwater.

- On-site land treatment is limited to those situations where non-refined hydrocarbon contaminated soils resulting from spills/leaks and non-refined hydrocarbon contaminated pit/pond sludges are land treated in a single application of the waste.

- The wastes must be land treated on the site on which they were generated and the licensee or approval holder of the site must address the procedures in the following sub-sections to ensure that no adverse environmental or health consequences occur.

- On-site land treatment operations must not compromise the ability to restore the site to meet reclamation certification requirements.

- Land treatment is not an option if more than one application is required to accommodate the volume of waste.

Licensees and/or approval holders of oil and gas sites must keep in mind that other treatment and disposal options such as soil washing, solvent extraction, biopile, biocell, thermal treatment, stabilization/solidification, and approved landfill disposal may be more applicable in some situations.

2. Assessment Information

Approval holders or licensees are not required to submit applications or information to the EUB for on-site, one-time land treatment operations occurring on active oil and gas sites. The approval holder or licensee of the site must document their activities, and supply this documentation to EUB or AEP staff upon request.

Because inappropriate spreading of wastes on land can damage soil that currently is not degraded, approval holders or licensees must ensure that on-site land treatment operations will not compromise future land capability. The framework described in this section is guided by the environmental objective of preservation or restoration of equivalent capability of the land and is designed to minimize the occurrence of unnecessary environmental damage. It is not acceptable, in the process of dealing with a volume of concentrated waste to create a second, larger albeit less concentrated, contaminated site.

Appropriate and comprehensive site and waste characterization are required to determine whether the site and receiving soil are conducive to land treatment and whether the waste is susceptible to biodegradation. Parameters that have proven to be of concern historically include hydrocarbon content, salt content, pH, metal concentrations, and environmentally persistent compounds such as halogenated organics.

A representative sample of the waste and receiving soil must, as a minimum, be analyzed for the following:

- pH
- electrical conductivity (EC)
- major soluble ions (Ca, Mg, Na, and Cl,)
- total metals (as per AEP Tier I Criteria)
- sodium adsorption ratio (SAR)
- texture (soil only)
- bulk density (waste only)
- hydrocarbon concentration (waste only)
- extractable organic halogen (waste only)
- assessment of the waste for suitability of biodegradation (i.e. hydrocarbon fractionation, treatability study, waste characterization)

On-site land treatment of oilfield waste as once-only application is possible if the following factors are met:

(a) The waste material contains less than 2 ppm organic halogen.

(b) The land treatment site does not have a slope that exceeds 5 per cent and is at least 100 meters away from any permanent body of water.

(c) The receiving soil (0-15 cm depth) does not exceed AEP Tier I Criteria for EC, SAR, metals, and pH.

(d) The maximum depth of the treatment zone must be at least 1 metre above the seasonally high water table. For groundwater protection the hydraulic conductivity of the subsurface soil below the treatment zone should be low. It is recommended that the subsoil exhibit a hydraulic conductivity of 10^{-5} cm/sec or less.

(e) Available area of receiving soil will result in a maximum spread rate of 75 kg waste per square metre (750 tonne per ha) or a waste to soil mix ratio of 1:4 by volume. This rate of application is not to be exceeded. Contaminated materials in excess of this capacity must be dealt with by other treatment means.

(f) After mixing the waste material with the receiving soil (assuming maximum mixing depth of 15 cm) the treatment zone meets the following:

  (i) maximum metal concentration does not exceed AEP Tier I Criteria,
  (ii) EC does not exceed 4 dS/m,
  (iii) maximum hydrocarbon concentration does not exceed 2 percent by mass,
  (iv) SAR does not exceed 6 (Note: if waste material alone does not exceed 2 then SAR determination after mixing is not required), and
  (v) pH is between 6.5 and 8.5.

(g) The maximum predicted time required to reduce the hydrocarbon concentration in the treatment zone to less than 0.1 per cent by mass does not exceed 5 years.

(h) Application of wastes does not occur during the period from October 15 to the next April 30, during rainfall periods, or at other times when the soil is saturated with water, ice-covered, snow-covered, or frozen.

3. Information Documentation

Information to verify that the factors listed in points (a) through (h) in subsection 2, Assessment Information above have been met, must be documented. Other information that must be documented for on-site land treatment of a single application of oilfield waste includes:

(a) soil horizon used for the treatment zone (Note: Land treatment conducted on subsoils, i.e. C horizon, may have reduced potential in meeting the 0.1 per cent hydrocarbon treatment target.),

(b) soil classification of the treatment site to the subgroup level (Agriculture Canada Expert Committee on Soil Survey 1987),

(c) number, location, and depth of samples taken to characterize the treatment area,

(d) sketch of the site identifying the treatment area and other key features such as slope, topography, and drainage features,

(e) area of land available for land treatment,

(f) volume of waste land treated (cubic metres),

(g) waste application rate,

(h) date of application,

(i) photo of the treatment area,

(j) estimated biodegradation period (years),

(k) description of application method and depth of application,

(l) amendments added to the treatment area (types, rates, and frequency), and

(m) confirmation treatment zone analyses (hydrocarbon concentration, pH, and EC) to verify successful biodegradation.

The documented information must be retained until a reclamation certificate for the site has been issued, and must be made available to EUB or AEP staff upon request.

16.3 Biocell and Biopile Treatment or Facilities

1. Introduction

Biocell or biopile techniques refer to the processes where oilfield wastes are biologically degraded in a contained and controlled environment, whether it is in an impermeable cell structure or piled on an impermeable liner. These techniques should be considered as alternatives to land treatment.

Biopile and biocell treatments may be of particular interest when:

- Site conditions are not suitable for land treatment.
- The volume of waste precludes one-time, on-site land treatment.
- Biodegradation of the organic contaminant is an intermediate step to make the waste suitable for another treatment or disposal option.
- The waste is intended to be used as fill material after successful biodegradation (i.e. material is excavated, treated, and then replaced).

Once the biodegradation process is complete the material must be removed from the contained system and forwarded for further treatment or disposal, or returned to the originating site to be used as fill material if it meets acceptable criteria. Biocells and biopiles must not be used for final disposition of waste materials.

2. General Requirements

Approval holders or licensees choosing to use biocells or biopiles for a one-time, on-site treatment of an oilfield waste on an active oil and gas or oil sands site are not required to apply to the EUB for approval. However, approval holders or licensees must document their activities including the system design, the type, volume, and characterization of the waste treated, and the final disposition of the treated material. Upon request, this information must be made available to EUB staff.

Approval holders or licensees constructing permanent biocells or biopiles on an existing EUB approved oil and gas or oil sands site for the purpose of biodegrading oilfield wastes generated at one or more of that approval holder's or licensee's facilities must submit an application for approval of modification to the facility. The application for modification shall address the information required in Section 26.0, *Biodegradation Facilities - Specific Application Information*.

Permanent biopiles or biocells constructed on a stand alone site require EUB approval as an oilfield waste management facility. Facilities that accept material from various sites as well as various companies will be considered third party waste receivers.

While this section outlines the primary criteria considered appropriate for biocell or biopile treatment, operators should refer to Sections 21.0 and 26.0 for the information required in an application for approval to construct or operate an oilfield biocell or biopile.

All biopiles and biocells shall comply with the requirements (siting, safety, waste characterization, design and operation, record keeping, and closure) outlined in Section 11.0, *Oilfield Waste Management Facilities*.

3. Siting

Although conducting the biodegradation process in a controlled system minimizes the potential for the transfer of contaminants to the soil, groundwater, and perhaps even the atmosphere, biopiles and biocells shall comply with the siting requirements outlined in Section 11.2, *Siting Issues*. In addition, potential sites shall be chosen so that the seasonally high water table is at least 1 metre below the base or bottom of the biopile or biocell.

4. Design and Operation

Although the key treatment process occurring within biocells and biopiles is biodegradation of the organic contaminant, if designed for it, these facilities may also be potentially used to leach and collect water soluble contaminants, such as salts, from the waste.

Biopiles typically are constructed on grade (the ground surface) and the waste material is laid in a pile or in windrows on an impervious liner or base pad. The material may be aerated by physically turning over the pile or windrows. Nutrients and moisture may be topically applied, or some designs may incorporate perforated pipes throughout the pile as the waste material is being laid down for the purpose of adding air, nutrients, or moisture. Some designs may also cover the pile for collection of off-gases such as highly volatile organics or CO_2.

Monitoring the CO_2 level can provide insight to the activity levels of the microorganisms responsible for biodegradation and may aid in determining when additional nutrients, air, or moisture is required or when the degradation process is nearing completion.

Within the scope of this document, the main difference between a biopile and a biocell is that a biocell consists of a walled containment system that may be constructed on grade or below grade. The waste material is then laid within the containment system.

In addition to the general design and operation requirements outlined in Section 11.6, *Design and Operation* the following requirements also apply.

(a) Biopiles and Biocells Used for One-Time Treatment

Biopiles and biocells used for a one-time, on-site treatment of oilfield waste shall, as a minimum, consist of a containment device and a leachate collection system.

(i) Containment Device

The containment device shall consist of a curbed (at least 15 cm in height) impermeable liner that is chemically resistant to the material being treated and exhibits a hydraulic conductivity of 10^{-7} cm/sec or less (i.e. an engineered compacted clay liner with a minimum thickness of 0.5m, a minimum of 30 mil geosynthetic liner, or current accepted standards), or of a steel, plastic, fibreglass reinforced plastic, or concrete vessel.

(ii) Leachate Collection System

The leachate collection system shall be designed to allow for the collection of any generated leachate, or in systems open to the atmosphere, precipitation.

Note: In situations where the soil conditions of the lease exhibit limited permeability (i.e. hydraulic conductivity of 10^{-6} cm/sec or less) and the contaminants within the waste material are relatively non-leachable, the waste material may be biodegraded on a prepared surface of the lease. This includes preparation of a base for the containment system (i.e. removal of A horizon and B horizon soils, and preparation of the C horizon soil for the base pad) and incorporation of the leachate collection system.

To use this option operators must verify that the hydraulic conductivity of the prepared surface is 10^{-6} cm/sec or less and assess the leachability of the waste. The waste material must not exceed an EC of 4 dS/m, SAR of 6, and hydrocarbon concentration of 2 per cent by mass. As well, a leachate of the waste prepared using the TCLP method, must not exceed the concentrations for BTEX and metals (As, Ba, Cd, Cr, Co, Cu, Pb, Hg, Mo, Ni, Se, Zn) in the CCME Interim Assessment Criteria for Water.

(b) Permanent Biopiles and Biocells

Permanent biopiles and biocells shall consist of a:

- primary containment device, a secondary containment system, a leachate collection system, and a leak detection system, or

- primary containment device, a leachate collection system and a groundwater monitoring system.

(i) Primary Containment Device

The primary containment device for a biocell shall consist of a impermeable liner or a steel, plastic, fibreglass reinforced plastic, or concrete tank or vault, while that for a biopile may consist of a curbed (at least 15 cm in height) impermeable liner or a curbed asphalt or concrete base pad.

Licensees and/or approval holders must be able to verify that liners used for primary containment meet the criteria specified in Section 16.3(4)(a)(i), on Containment Devices.

(ii) Secondary Containment System

The secondary containment system shall consist of an impermeable clay or synthetic liner that is chemically resistant to the material being treated and exhibits a hydraulic conductivity of 10^{-6} cm/sec or less (i.e. 0.5 metres or more of an engineered compacted compacted clay liner, a minimum of 30 mil geosynthetic liner or current accepted standards). Licensees and/or approval holders must be able to verify that the liner meets the above criteria.

(iii) Leachate Collection System

The leachate collection system shall meet the requirements outlined in Section 16.3(4)(a)(ii), on Leachate Collection System.

(iv) Leak Detection System

Licensees and/or approval holders must be able to monitor the interstitial space between the primary containment device and the secondary containment device to ensure the primary containment device is not leaking (i.e. incorporation of engineered seepage pathways flowing to a monitoring well).

When the biopile or biocell is in use, the leak detection system must be sampled on a monthly basis and if any liquid is present, it must be field tested for pH, chlorides, hydrocarbon odour, and visible hydrocarbon sheen. If there is indication of a problem from the monthly tests, then laboratory analysis should be performed for verification and then followed by appropriate corrective measures if necessary.

(v) Groundwater Monitoring

Applicants wishing to construct a permanent biopile or biocell that consists of only a primary containment system and leachate collection system shall be required to incorporate into the design, a groundwater monitoring system that will provide an early indication of potential groundwater impact. Refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection.*

(c) Other Operational Requirements

The following operational requirements also apply to all biopiles and biocells (permanent as well as those used for one-time treatment):

(i) Prior to treatment, a representative sample of the oilfield waste must, as a minimum, be analyzed for the following:

- pH
- EC
- major soluble ions (Ca, Mg, Na, and Cl,)
- total metals (as per AEP Tier I Criteria)
- hydrocarbon concentration
- extractable organic halogens

(ii) The success of the treatment shall be verified by analyzing the treated material for the parameters listed in point (i) above. If the original analyses indicated that levels of salts, metals, or extractable organic halogens were not a problem then those parameters may not have to be repeated. Depending upon the final disposition the treated material may require further testing. It is the responsibility of the licensee and/or approval holder of the site on which the treatment system is located to characterize the material to verify it's suitability for final disposition.

(iii) In the event of any volatile or particulate emissions, the operator shall incorporate adequate controls to mitigate any potential problems.

5. Reporting and Record Keeping

In addition to the record keeping requirements outlined in Section 11.8, *Record Keeping* the following requirements also apply.

Licensee and/or approval holders of sites on which biopiles and/or biocells (permanent or one-time) are constructed shall, for each volume of oilfield waste biodegraded, document the following information and retain it on site for a minimum of two years beyond the date the biodegraded material was removed from the treatment system. The following information must be made available to EUB staff upon request:

(a) the type, volume, origin, generator, and analyses, as per 16.3(4)(c)i), of the waste material,

(b) the types and application rates of any amendments added to enhance the biodegradation process,

(c) the volume of any leachate collected and how it was disposed,

(d) the analyses of the treated material, as per 16.3(4)(c)ii), to verify the material meets the criteria for the next treatment or disposal option,

(e) where the treated material was transferred (name and location of the site or facility) for final disposition or for further treatment,

(f) if applicable, the leak detection results, and

(g) if applicable, the groundwater monitoring results (which must be retained for a minimum of five years).

Note: The EUB Calgary office and AEP must be notified if any of the monitoring results indicate a concern. The notification shall describe:

- the parameters that changed,
- the investigative work conducted, and
- any remedial or corrective work that has occurred or is proposed.

6. Closure

In addition to the closure requirements outlined in Section 11.9, licensees and/or approval holders of sites that have used a biocell or biopile for a one-time, on-site treatment of oilfield waste will be required after biodegradation is complete, to remove the treated material, to dismantle the biocell or biopile, and to return the site of the treatment area to equivalent land capability. Operators will be required to document their closure activities, and to retain this information for a minimum of two years beyond the date equivalent land capacity was achieved. This information must be made available to EUB and AEP staff upon request.

17.0 Thermal Treatment

17.1 Introduction

The **purpose** of this section is to establish the minimum requirements for the design and operation of fixed thermal treatment facilities and to provide general information for non-fixed thermal treatment facilities used to treat oilfield wastes.

Thermal treatment is an effective method for removing organic components in oilfield waste and includes:

- incineration,
- thermal oxidation,
- thermal desorption,
- thermal phase separation, and
- thermal distillation recovery.

In these requirements, thermal treatment refers to:

Any process involving the use of heat to remove contaminants from, or destroy contaminants in, an oilfield waste material.

The treatment may involve destruction, recovery or reduction of the contaminants and/or the waste material in which it is found. Although these requirements were developed based on the above removal and destruction technologies, the requirements will apply, where applicable, to other thermal treatment technologies as they become commercially available in Alberta.

Thermal treatment technologies and facilities addressed in this section include small batch feed incinerators, campsite incinerators, and fixed thermal treatment facilities.

- Small batch feed incinerators, which are not allowed to burn more than ten tonnes of waste per month, and campsite incinerators operating at oil and gas or oil sands facilities do not require approval from the EUB provided they meet the criteria specified in Sections 17.3 and 17.4.

- All other fixed thermal treatment facilities, operating at oil and gas, oil sands, or oilfield waste management facilities must be approved by the EUB; refer to Part E, for information required in the application for approval to construct and operate a thermal treatment facility.

- Non-dangerous oilfield waste may be incinerated at AEP regulated incinerators that are approved to incinerate non-hazardous or hazardous wastes. The incinerator must also be approved to accept third party waste.

- Dangerous oilfield waste may be incinerated at AEP regulated incinerators that are approved to incinerate hazardous wastes. The incinerator must also be approved to accept third party waste.

The use of AEP approved mobile thermal treatment units on oil and gas facilities is discussed in Section 17.5, *Mobile Thermal Treatment Units*.

17.2 Thermal Treatment Facilities Requiring Approval to Operate

This subsection applies to fixed thermal treatment facilities that do not meet the criteria described for small batch feed or campsite incinerators. An application containing information outlined in Part E, must be submitted to the EUB. Successful applicants will receive an "Oilfield Thermal Treatment Facility Approval" from the EUB. No on-site construction work or test burns shall commence prior to receiving the approval.

Thermal treatment facilities shall comply with the requirements (siting, safety, waste characterization, EIA, design and operation, site assessment and groundwater protection, record keeping, and closure) outlined in Section 11.0, *Oilfield Waste Management Facilities*.

1. Siting Issues

Siting of thermal treatment facilities must consider the following issues:

regional geology,
hydrogeology,
topography,
set-back distances,
adjacent land uses,
future land uses,
environmental sensitive areas, and
public impact.

In addition to the general siting requirements in Section 11.2, *Siting Issues* for all oilfield waste management facilities, special consideration should be given to air quality issues and dispersion characteristics in the local area.

2. Waste Feed Restrictions

Certain waste feed restrictions may be identified in an approval depending on the thermal treatment technology and process being used (i.e. a limitation could be placed on the halogenated organics content in the waste feed stream). These restrictions will be individually reviewed for each application.

Waste feed streams must not contain polychlorinated biphenyls (PCBs). The waste stream should be classified in accordance with Part B, Section 5.0, *Procedures for Classifying Waste* and must not contain detectable PCBs using the test method selected from Appendix 3.0, *Recommended Test Methods*.

3. Design Parameters

The application for approval must specify the key parameters which would indicate the successful destruction or removal of contaminants and the success of pollution control equipment. The limiting operating values of these parameters must be identified with a discussion of why the identified limits apply.

For traditional incineration technologies this may include:

primary chamber temperature,
primary chamber pressure,
afterburner temperature,
afterburner residence time,
afterburner excess oxygen,
treated material residence time, and
exit temperatures.

For thermal desorption technologies some or all of the previous may apply, as well as:

- gas exit temperature from the vapour cooler, and
- carbon bed pressure drop.

4. Operating Practices

(a) Waste Handling and Storage

Waste materials must be stored in accordance with the EUB ID 95-03 and Guide G-55 *Storage Requirements for the Upstream Petroleum Industry*. Stored waste volumes must not exceed six months processing volume.

Written operating practices must be maintained at the operating site which identify the receiving, unloading and segregation practices for all potential waste streams.

(b) Operating and Safe Work Procedures

In addition to a corporate emergency response plan, written operating procedures must be maintained on-site which address start-up, shutdown, emergency shutdown, and other safe work procedures as required. These procedures must be designed to control the emission or discharge of contaminants or untreated material during start-ups and shut downs.

(c) Upsets

All equipment must be equipped with an automatic alarm system to be triggered when preset levels of the key design parameters are not met. Alarms must be designed to provide an indication of impending upset conditions. Written operating practices detailing the appropriate response to each alarm must be maintained on site.

(d) Feed Conditioning

Conditioning of the feed, such as a thorough mixing with processed or uncontaminated materials is acceptable, provided that the mixing is done for operational purposes. To ensure compliance with the operating approval, waste stream characterization must be performed prior to feed conditioning. However, dangerous oilfield wastes must not be mixed with any solid or liquid for the primary purpose of dilution to avoid any Alberta regulatory requirement.

5. Residuals Management

Subject to characterization of both the solid and liquid residual materials produced from thermal treatment operations, reuse, recycle or disposal options may be chosen. Part B, Section 5.0, *Procedures for Classifying Waste* gives guidance on how to conduct this characterization. Licensees and/or approval holders of thermal treatment processes must ensure that they inform the oilfield waste generator of the capabilities of their system so that the generator can assess the liabilities associated with the treated material.

(a) Solid Residuals

Providing the residual material meets AEP Tier I Criteria, suitable options include using it as on-site fill material or as landfill cover material. If treatment did not occur on-site, ash or treated soils may be returned to the oilfield waste generator's site.

The use of treated materials as landfill cover must not contravene any conditions in the AEP or EUB landfill licence or approvals and may require written agreement of AEP or EUB..

Ash or processed soils may be landfilled provided it is tested and meets the requirements of Section 15.0, *Oilfield Landfills*.

(b) Liquid Residuals

Liquid residuals should be collected and reused in the process as much as possible. Collected liquids which will not be reused may be recycled as long as the characteristics of the material meet all receiver specifications for that product stream. Cooling water may be treated and released to surface provided that it is tested and meets the criteria in Section 11.6(2)(b), *Design and Operations* prior to a controlled release.

Alternatively, liquids may be injected into waste disposal wells approved to handle the liquids or they may be disposed in any other manner approved by the EUB.

6. Emissions Criteria

Operations at thermal treatment facilities must not result in environmental damage or risk to public safety. Typically, facilities will be expected to achieve the emission levels identified in the following table.

Table 17.1 - Stack Discharge Limits (at 11 per cent Oxygen)

Parameter	Emission Limit
Hydrogen Chloride	75 mg/Rm^3
Particulates	20 mg/Rm^3
Visible Emissions - Opacity	5 per cent (averaged over 6 consecutive minutes)
Carbon Monoxide	57 mg/Rm^3
Dioxins and Furans	0.5 mg/Rm^3
Sulphur Dioxide	260 mg/Rm^3
Oxides of Nitrogen	400 mg/Rm^3
Destruction and Removal Efficiency	99.99 per cent

mg/Rm^3 - milligrams per dry cubic metre at a reference pressure of 1 atmosphere and reference temperature of 25°C.

Stack emission levels for a facility are dependent on a number of parameters which include:

volume of waste being treated,
type of waste being treated,
technology being used, and
site specific requirements.

Applicants should consult the following guidelines to identify the specific emissions criteria which pertains to their thermal treatment process in developing their application information. Supporting data must be provided with explanations for the choice of criteria.

- National Guidelines for Hazardous Waste Incineration Facilities, Design and Operating Criteria, Volume 1. Canadian Council of Ministers of the Environment, March 1992.

- Operating and Emissions Guidelines for Municipal Solid Waste Incinerators. Report CCME-TS/WM-TRE003. June, 1989.

7. Test Burns and Compliance Tests

For further details on requirements for test burns or compliance tests, refer to the "National Guidelines for Hazardous Waste Incineration Facilities, Design and Operating Criteria, Volume 1", Canadian Council of Ministers of the Environment, March 1992.

(a) Test Burns

The main objective of a test burn is to acquire quantitative data that will be representative of the actual thermal treatment operations. These tests are conducted to ensure that the facility can properly treat the waste and meet all performance requirements and contaminant emission limits.

Successful completion of a test burn will be a condition of an EUB approval to operate. The application for approval to construct and operate a thermal treatment facility must outline the test burn protocol that will be followed. Information in the application should include:

(i) waste type(s) and source(s),
(ii) waste feed characterization, including the sampling and analysis methods used,
(iii) parameters to be monitored in all effluent streams, including sampling and analysis methods used,
(iv) operating parameters such as temperature, air flow rate, mass flow rate, waste feed rate, residence time, total hydrocarbons and combustion and destruction efficiencies (if applicable), and
(v) the time period over which the test will be conducted.

Further testing may also be required for approved facilities if the operator wishes to:

- change the facility design or operating conditions,
- alter the waste feed stream matrix, or
- if the principle contaminants in the waste feed changes.

(b) Compliance Testing

Compliance testing may be required on certain approved thermal treatment facilities. The need for compliance tests will depend on the thermal treatment technology being used and other factors such as the monitoring procedures at the facility. The purpose of conducting these tests is to ensure that the facility continues to comply with existing standards and the requirements identified in the facility approval.

The need to conduct compliance testing and the procedures and requirements to follow during a test will be determined for each individual facility. The frequency of testing will be identified in the facility approval.

8. Monitoring and Reporting

In addition to the record keeping requirements in Section 11.8 *Record Keeping*, for all oilfield waste management facilities, the following requirements also apply.

(a) Inspections

Daily inspections of the facility must be conducted to detect leakage, spills, corrosion, hot spots, and malfunctions. Equipment shall be examined for wear and signs of leaks. Results of these inspections should be recorded in the daily operations log with operational changes made to correct deficiencies.

(b) Process and Stack Emission Monitoring

The key parameters which indicate the successful destruction or removal of contaminants and successful pollution control operations should be monitored on a continuous basis. Where continuous monitoring is not employed, alternative monitoring or operational methods which would prevent operating upsets must be identified in the application.

Ambient air quality monitoring may also be required by the specific treatment facility approval.

(c) Groundwater Monitoring

A comprehensive groundwater monitoring program must be included in the design, operation, and decommissioning of a thermal treatment facility that requires approval to operate from the EUB.

(d) Monthly Documentation

Licensees and/or approval holders of thermal treatment facilities must document the following information and retain it on-site for a minimum of two years. The following information must be made available to EUB staff upon request:

(i) a balance of opening inventory (waste materials and residuals) for each month,

(ii) for each receipt of waste material, the volume, source, generator, type (characterization), and date received,

(iii) the volume of waste material thermally treated (daily) including the volume of residuals generated (liquids and solids),

(iv) the daily operational information from the continuous process and emission monitors, including identifying and briefly explaining any occurrences lasting more than 60 minutes where operating parameters or emission limits were not met,

(v) a closing inventory balance for the month identifying total volumes of waste materials received, total volume thermally treated, total volume of waste material waiting for treatment, volume of residuals sent for disposal, and the name and location of the disposal facility, and volume of residuals stored on site, and

(vi) copies of all analyses conducted for the purposes of feed characterization.

(e) Annual Report

Licensees and/or approval holders of thermal treatment facilities must summarize the monthly information and prepare an annual report by March 31 of each year. This report which must be retained on site for a minimum of 2 years and made available to EUB staff upon request, shall contain as a minimum:

(i) the amount of material processed, including sub-totals for different waste streams,

(ii) a listing of the types of contaminants processed,

(iii) the amount of residual materials disposed and the disposal method,

(iv) a description of the performance of the air pollution control equipment,

(v) a summary of the process monitoring results,

(vi) a general description of operations, and

(vii) a summary of the results of groundwater monitoring programs (if any).

17.3 Campsite Incinerators

Portable incinerators having a burning capacity of less than 90.7 kg/hr which are used to dispose of kitchen camp wastes from drilling and exploration sites do not require an approval from the EUB. The EUB advises the use of these campsite incinerators in areas where access to an approved disposal site is not available.

The incinerator shall:

1. be capable of burning the waste to an inert ash,

2. incorporate a stack of suitable height and an effective spark arrestor,

3. be maintained in good operating condition such that warped components, leaks, refractory, or other damage is repaired as soon as is practicable,

4. be provided with underfire air, and

5. be provided with overfire air for all incinerator types excepting controlled air units.

Considerations should be given to the requirements of the Air Emissions Regulation (AR 124/93).

17.4 Small Batch Feed Incinerators

Basic principles of good incinerator design have been used to develop the following criteria. No formal approval from the EUB is required for these small incinerators to operate on oil and gas or oil sands sites, provided that all the requirements of this guideline are met. The licensee and/or approval holder of the oil and gas or oil sands site is required to send notification to the main EUB (Calgary) office. The notification should identify the company name, location of the site, the approximate volumes of waste types I, II, and III (refer to Table 17.2), and filter material that will be batch incinerated at the site, and that all of the requirements of this section will be met.

1. Siting

These guidelines apply to small non-mobile incinerators owned and operated by the waste generator. Facilities where oilfield waste incineration is occurring must be located a minimum of 1.5 km from any residents or public facility, unless otherwise approved by the EUB.

The surface terrain of the incinerator site shall allow for the prompt and effective clean up of all materials that may spill or leak during waste storage and disposal operations. The clean-up materials should be disposed of in the incinerator.

Maximum ground level ambient pollutant concentrations shall not encompass any occupied dwelling, watercourse, food processing establishment, farm building with livestock, or feedlot and feed processing or handling establishment.

2. Waste Feed Restrictions

The feedstock for the small oilfield incinerators described in this section is limited to waste types I, II and III (as listed on Table 17.2) and oilfield filter material. Oilfield filter material is defined as all types of disposable filters from oil and gas production operations including vehicle filters, oil pads, and absorbents used in maintenance of such operations. These wastes must be generated on the oil and gas site where the small incinerator is located, or if the incinerator is located on a battery or gas plant, wastes can be accepted from associated well sites, provided these sites have the same licensee as the site on which the incinerator is located.

The incinerators are to be used for batch feed only with a limit of one charge per day. The maximum allowable percentage of filter material (by weight) in any one charge is 50 per cent. Filter material must be burned with waste types I, II or III so as not to exceed the 50 per cent limit. Continuous flow through the incinerator is prohibited. A maximum volume of 10 tonnes of waste per month may be incinerated.

3. Design Parameters

(a) Feed System

Manual feed systems for batch loading the incinerator is the basis of these guidelines. Applicable OH&S regulations must be complied with when handling the wastes. The incinerator should be sized such that not more than one charge per day is required to handle the waste quantities. A safety system to warn of firing or a high temperature in the primary chamber when loading is required. The incinerator should not be loaded if the primary temperature is above the boiling point of any of the waste's liquid residue.

(b) Primary Chamber

(i) The volume of the primary chamber should be designed to allow for a total heat release rate of between 445,000 kJ/h/m^3 (12,000 BTU/h/ft^3) and 670,000 kJ/h/m^3 (18,000 BTU/h/ft^3). A heat release rate of over 670,000 kJ/h/m3 (18,000 BTU/h/ft^3) is not recommended for use in the design as this may lead to uncontrolled conditions, resulting in high particulate emissions and the discharge of incomplete combustion products to the environment.

(ii) The hearth area should be designed to allow a burning rate of 58.5-78.0 kg/h/m^2 (12-16 lb/h/ft^2).

(iii) The floor should have a recessed area or otherwise have the ability to contain liquid drippings from filters thus allowing incineration during the cycle.

(iv) Temperature in the primary chamber should be maintained in the range of 400-760°C. Avoiding temperature peaks above 760°C will minimize excursions in gas velocities, thereby reducing ash carry-over and particulate emissions. Care should be taken to ensure the primary temperature is always above the auto-ignition temperature of the waste, especially low heating value wastes.

(v) The external casing of the chamber should be designed to maintain a maximum temperature of 70-90°C. This can be accomplished with the use of refractory and/or insulation materials. Where appropriate, an expanded metal shield or other suitable means of shielding should be installed for the protection of personnel.

(vi) The temperature in the primary chamber should be controlled by a sensor located at the breaching. When water-wet or low heating value wastes (<6000 kJ/kg) are incinerated, the sensor should be connected to a system to provide automatic temperature control through a modulating or on/off primary chamber burner.

(c) Secondary Chamber

(i) The temperature in the secondary chamber should be designed with an operating temperature of not less than 1000°C during the incineration cycle.

(ii) The incinerator should be designed to provide no less than 6 per cent residual oxygen on a dry basis in the flue gas exhaust from the secondary chamber.

TABLE 17.2

Classification And Design Data Of Wastes To Be Incinerated

Type of Waste	Description	Principal Components	Approximate Composition % by Weight	Moisture Content % (Design Maximum)	(Average) Incombustible Solids %	kJ Value per kg of Refuse as Fired (Design Minimum)	Required Minimum Burner Input (kW per kg Waste)
I*	Rubbish	Combustible waste, paper cartons, rags, wood scraps, floor sweepings; domestic, commercial industrial sources.	Rubbish (80-100) Garbage (20-80)	25	10	15000	0
II*	Refuse	Rubbish and garbage; residential sources.	Rubbish (35-80) Garbage (65-20)	50	7	10000	1.3
III*	Garbage	Animal & vegetable wastes, restaurants, hotels, markets; Institutional, commercial, and club sources.	Garbage (65 - 100) Rubbish (0 - 35)	70	5	5815	1.9
IV**	Animal solids and organic wastes	Carcasses, organs, solid organic wastes; hospital, laboratory abattoir, animal pound, and similar sources.	100 animal and human tissue	62	9	2300	7.5
V	Gaseous liquid or semi-liquid wastes	Industrial process wastes (tars, paints, solvents, fumes).	Variable	Dependent on predominant components.	Must be determined by wastes survey.		Must be determined by wastes survey.
VI	Semi-solid and solid	Combustibles requiring hearth, retort, or grate burning equipment (rubbish, plastics, wood wastes).	Variable	Dependent on premoninant components.	Must be determined by wastes survey.		Must be determined by wastes survey.

* The above figures are recommended for use in computing heat release, burning rate, velocity and other details of incinerator design.

** Type IV wastes require a "heated hearth" type of incinerator.

(iii) The secondary chamber should be designed for a gas residence time of not less than 1 second at 1000°C. This residence time is to be based on the volume of the secondary chamber from the flame from to the location of the temperature sensing device. These calculations or a vendor guarantee must be available on-site for inspection by EUB staff.

(iv) The residence time of gases in the combustion chamber may be calculated using the following formula:

$$V_T = V_p + V_m$$

Where:

V_T = total volumetric flow rate in m^3/sec at 1000°C
V_p = volumetric flow rate of dry combustion products at 1000°C
V_m = volumetric flow rate of moisture at 1000°C

(v) Therefore, the active chamber volume required to achieve one-second retention time is the volume in m^3 from the equation (V_T) in the above formula. ("Dead" areas with little or no flow should not be included in the retention volume). It should be noted that in sizing the secondary chamber to meet the one-second retention time required, the length of the chamber should be calculated from the flame front to the location of the temperature sensing device.

(vi) The temperature in the secondary chamber should be controlled by a sensor located at a point representing one second retention time from the flame front or final air injection points. The sensor should be connected to a system to provide automatic temperature control and it should also regulate the modulating secondary chamber burner.

(vii) The refractory surface of the secondary chamber should be heated over a minimum period of half an hour, prior to feeding waste into the incinerator, to ensure optimum conditions for the destruction of any volatile organic compounds.

(viii) The external casing of the secondary chamber should be designed to maintain maximum temperature of 70-90°C by means of insulation and refractory. For the protection of personnel, an expanded metal shield or other suitable means of protection should also be installed on the casing.

(d) Turbulence

(i) Gas turbulence is an important parameter in the design of incinerators and can be achieved by a high combustion gas velocity, tangential air injection, abrupt changes in flow direction, and the installation of combustion gas restrictions (e.g. orifices, checker work, or baffles).

(ii) Turbulence is difficult to quantify; however, use of the Reynolds number (Re) has been suggested to provide an indication of the gas phase turbulence in the incinerator. An example of the calculation of the Reynold's Number is provided in Part F, Appendix 5.0.

(iii) Preferred designs would have a calculated Reynolds number in the secondary chamber over 10 000 to ensure turbulent flow. Lower numbers plus other turbulence adding features may be adequate. The secondary burner must be designed as per the following combustion air requirements. These calculations or a vendor guarantee must be available on-site for inspection by EUB staff.

(e) Combustion Air Requirements

(i) For starved-air incinerators, air into the primary chamber should be supplied at 30 to 80 per cent of that required for stoichiometric combustion. Primary air supply must be through multi ports to ensure air distribution through the waste.

(ii) The air supply in the secondary chamber of all incinerators should be able to provide excess air at 40 to 150 per cent of that theoretically required during the peak burning rate.

(iii) The combustion air supply should be automatically adjustable with a Temperature Recorder Control System to maintain the set temperatures in the primary and secondary chambers of the incinerator.

(f) Burners

(i) The burners must be able to maintain a stable flame throughout the range of pressures, input rates, and fuel/air ratios experienced in the primary and secondary chambers.

(ii) The primary burner should be designed:

- to supply a minimum of 80 per cent of the total heat input of the incinerator design capacity;

- to modulate to a low "holdfire" setting to protect the burner throughout the incineration cycle.

(iii) The burner(s) in the primary chamber should be:

- located at a downward angle to provide maximum impingement of the flame onto the wastes. The alignment of the burner(s) should not allow the flame to impinge on the refractory walls or on other burner(s);

- set to maintain a temperature of 400-760°C in the primary chamber once the burn cycle is initiated;

- constructed with a sealed casing to eliminate the flow of tramp air into the chamber.

(iv) The burner(s) in the secondary chamber should be:

- mounted to promote thorough mixing plus flame and air penetration throughout the whole chamber. The alignment of the burner(s) should not allow the flame to impinge on the refractory walls or on other burner(s);

- set to maintain a temperature of not less than 1000°C in the secondary chamber at all times;

- fully modulated with a low "holdfire" setting to ensure a flame throughout the incineration cycle.

(g) Process Monitoring/Control

(i) One, preferably two, viewports should be installed in the primary chamber immediately behind the burners to facilitate visual inspection of the burn. The location should be selected to reduce particulate impingement, so that the viewport will remain relatively clean.

(ii) A Temperature Controller should be used to control the primary and secondary temperature by:

- turning off or reducing the heat input from the burner; and

- turning off, throttling back, or increasing the air supply.

(iii) All incinerators should be equipped with continuous primary and secondary temperature monitoring equipment on-line for the full cycle of operations. Recording is not required.

(h) Incinerator Stack

(i) For natural draft systems, calculations for stack design should be based on a secondary chamber gas temperature of 1000°C. If substantial heat losses through the stack are expected, such losses should be taken into account in determining the average stack temperature and the available draft. Equivalencies to these procedures will be considered.

(ii) The stack height should be calculated to provide a minimum available draft of 6.3 mm (0.25 in) water gauge (W.G.) at the breaching. The latter is an absolute minimum draft provision for all natural draft incinerators and must result in a draft of at least 2.5 mm (0.1 in) W.G. at the burner air inlets. Perry's Chemical Engineers' Handbook outlines procedures for calculating stack draft. Equivalencies to these procedures will be considered.

(iii) Each incinerator stack height shall be designed to comply with the EPEA Ambient Air Objectives as amended from time to time and the anticipated stack emissions which follow in sub-section 17.4.5. A study using an approved air modeling program shall be required in order to show that the incinerator stack is in compliance. Worst case calculations will be required to determine the necessary stack height incorporating topography, structures, and tree height. Emissions to be studied are SO_2, HCl, NO_x and particulates. The results of this study shall be maintained on-site and available for EUB inspection.

4. Operating Practices

(a) Operator Training

Incinerator operators should be properly trained and be familiar with all the manufacturer's operating procedures for the unit.

(b) Inspections

Incinerators should be visually inspected before each burn. Ensure primary holes are clear of any buildups.

(c) Waste Handling and Record Keeping

Waste should be categorized by weight and logged prior to charging to ensure that the design feed rate is not exceeded and to maintain a record of the quantities of waste processed. Source and description of wastes should be recorded and retained at the incineration site for a minimum of two calendar years. Therefore, all records are maintained as 12-month groups.

(d) Waste Charging

Waste should be charged into the incinerator during operation or until the full cool down cycle has been completed. Filters must not be stored in the primary chamber prior to incineration to avoid excessive liquid draining from them.

(e) Incinerator Preheating

The secondary chamber should be heated to operating temperature prior to the ignition of the primary chamber, to ensure optimum conditions for the destruction of the waste.

(f) Ash, Removal, and Disposal

(i) Ash resulting from the incineration of waste may contain significant levels of heavy metals. Therefore, care should be exercised in disposing of incinerator ash. Metal filter cores may be recovered and sent to scrap metal recyclers.

(ii) The incinerator ash should be evaluated according to the TCLP leachate test specified in Part F, Appendix 3.0. Ash passing the leachate test can be sent to an approved landfill and disposed of with due regard to Section 15.0, *Oilfield Landfills*.

(iii) The incinerator ash should be stored and transported in enclosed containers.

5. Emission Criteria

The anticipated stack emissions are listed in the following table:

TABLE 17.3

Stack Emission Limits For Small Batch Feed Waste Incinerators

Parameter	Emission Limit*
Particulates	230 mg/Rm^3
Hydrogen Chloride	75 mg/Rm^3
Carbon Monoxide	57 mg/Rm^3
Sulphur Dioxide	0.15 kg of SO_2 per kg of waste consumed up to a maximum of 100 kg of SO_2 per day
Opacity	20 per cent

* The emission limits are based on the maximum one-hour average concentrations that are calculated on a dry basis corrected to 11 per cent oxygen at 25°C and 101.375 kPa.

The anticipated incinerator stack emissions are determined within the stack, based on approved sampling and analytical protocol. All stack sampling facilities and survey methods shall comply with the requirements described in the document entitled *Stack Sampling Code (Ref. 89)* as amended from time to time and issued by the Standards and Approvals Divisions of Alberta Environmental Protection.

6. Performance Test

Testing of incinerator emissions are based on the design processing capacity of the incinerator while processing oilfield wastes. The performance test is to be done once only, within 90 days of initial start-up.

Primary and secondary temperature versus time profile must be recorded. Incinerator cycles and testing periods must be superimposed upon the profile.

Additional testing details are outlined in Section 7 of the document entitled *Guidelines for Design and Operation of Refuse Incinerators in Alberta* as amended from time to time and issued by Alberta Environmental Protection.

7. General Information Requirements

The licensee and/or approval holder of the oil and gas site shall for each new installation prepare a report containing the following items, retain it on-site for as long as the incinerator is on the site, and provide it to the EUB upon request:

(a) a copy of such plans, specifications, and technical information as may reasonably be required to determine compliance with the provisions of Section 17.4,

(b) a description of the waste to be incinerated, identified according to a waste survey and the types of waste listed in Table 17.2, and the average and maximum percentage by weight of each type. The description should also include the maximum batch charging rate and the maximum amount of waste to be incinerated daily. Refer to application information and details per the document entitled "Guidelines for Design and Operation of Refuse Incinerators in Alberta" for further guidance with respect to the information that should be contained in this report,

(c) the results of the performance test done within 90 days of initial start-up, as described in the previous section, and

(d) a description of the disposal option used for the ash resulting from the incineration of wastes.

8. Information Documentation

The approval holder or licensee of an oil and gas or oil sands site on which a small batch feed incinerator is located shall document the following information and retain if on site for a minimum of 2 years. Upon request, this information must be made available to EUB staff.

(a) for each batch of waste incinerated, the weight, volume, waste type, source, date incinerated, and volume residuals generated, and

(b) any daily operational, inspection, and maintenance information.

17.5 Mobile Thermal Treatment Units

1. Jurisdiction

The EUB does not currently issue approvals for mobile thermal treatment units. These facilities will continue to be under the jurisdiction of Alberta Environmental Protection (AEP).

2. Operation at Oil and Gas Facilities

Mobile thermal treatment units which either have received approval from or have been registered with AEP may operate at oil and gas facilities provided that:

(a) All thermal treatment operations comply with the operating requirements of the existing oil and gas facility,

(b) All operations are in accordance with the thermal treatment approval or registration conditions from AEP. Dangerous oilfield wastes must only be treated by units approved by AEP to treat hazardous waste,

(c) Only wastes from the site where the unit is located at may be treated or, if the site is a battery or gas plant, wastes from the associated well sites provided these sites have the same licensee as the site on which the incinerator is located, and

(d) If the operation of a mobile unit is expected to exceed a time period of six months, the possible impacts of the operation must be reviewed in consultation with the EUB Calgary office.

It is the responsibility of the licensee and/or approval holder of the oil and gas or oil sands site to ensure that on-site operations involving mobile thermal treatment units do not result in any contravention of the approval issued for the oil and gas production facility. This includes compliance with the above requirements a) through d) and any further restrictions which may be dictated by specific site conditions.

3. Notification of Operations

The licensee and/or approval holder of the oil and gas facility shall, **30 days** prior to commencement of thermal treatment operations, submit to the main EUB Calgary office, written notification containing the following:

(a) the location of the oil and gas site on which the mobile unit will be located,

(b) the company/operator of the mobile unit and the AEP license/approval or registration number,

(c) the volumes, types, and sources of the wastes to be treated by the mobile unit,

(d) the final disposition of the treated material, and

(e) the duration of the activity.

The licensee and/or approval holder of the oil and gas or oil sands facility shall ensure that all landowners and residents within **1.5 kilometers** are notified of the details of the intended activity at least 30 days prior to commencement of thermal treatment operations. Note: If the operating licence for the mobil thermal treatment unit also identifies conditions for public notification, then the most stringent public notification requirements must be met.

The local EUB area office shall be notified by the Licensee and/or Approval Holder of the oil and gas facility of the details of the intended activity at least **48 hours** prior to commencement of thermal treatment operations. In practice, it would be advisable to notify the EUB area office at the same time as the public are notified.

PART E

APPLICATION REQUIREMENTS FOR

OILFIELD WASTE MANAGEMENT FACILITIES

Part E

Application Requirements for Oilfield Waste Management Facilities

18.0 Overview of the Application Requirements

The purpose of this section is to outline the information that needs to be addressed in an application for approval to construct and operate an oilfield waste management facility.

An oilfield waste management facility may consist of one or more of the following components:

- waste storage area/facility,
- waste transfer station,
- waste processing facility,
- waste disposal well (class Ia or Ib),
- surface facilities associated with waste disposal wells,
- landfill,
- biodegradation facility (biopiles or biocells),
- thermal treatment facility, and
- other oilfield waste management technology or facility.

Applicants considering any of the waste management components listed above should review the applicable sections of Part D, *Oilfield Waste Management Facilities*, for design and operation requirements.

When the proposed waste management component is to be constructed on an existing EUB approved oil and gas or oil sands facility, the type of component as well as the volume and characteristics of the waste material to be handled, will dictate whether notification or application is required. Applicants should refer to the applicable section in Part D for more details. Applicants who intend to integrate a waste management component with a new oil and gas or oil sands facility shall include the appropriate information for the waste management component with the facility application. When appropriate, the waste management component will be covered in the facility approval.

Unless otherwise approved by the EUB, the wastes treated by the waste management component must be generated on the oil and gas or oil sands site where the component is located. If the component is located on a battery or gas plant, wastes can be accepted from associated well sites provided the well sites have the same licensee as the site on which the waste management component is located. In the situation where the waste management component is located on a wellsite and the wellsite is a satellite of a battery, wastes generated at the battery and its associated wells may be treated at the waste management component provided the licensee of the wellsite and the battery are the same. Closure of the waste management component will be included in the overall facility closure, with the exception of landfills and fixed thermal treatment facilities other than small batch feed and campsite incinerators, financial assurance will not be required.

When the proposed waste management component is to be constructed on a stand-alone site, the applicant must obtain approval from the EUB to construct and operate an oilfield waste management facility. Oilfield waste management facilities can be first party or third party waste receivers as outlined in their approval to operate.

With the exception of Class Ia waste disposal wells, EUB approved waste management facilities shall only accept wastes generated in the upstream petroleum industry. Receipt of downstream and other industrial wastes is prohibited at EUB approved facilities. Applicants interested in accepting both oilfield wastes and downstream or other industrial wastes must seek direct approval from AEP.

All applicants for any oilfield waste management facilities must address the information requested under Section 21.0, *General Information,* which includes introductory, assessment, site, development, and closure information.

- *Introductory Information* includes the name of the applicant, the name and location of the facility, and the waste handling, treatment, or disposal method(s) described within the application.

- *Assessment Information* pertains to information required to assess the impact and necessity of the proposed facility. Section 19.0, *Environmental Impact Assessments*, addresses the possible requirement for an EIA for a proposed facility.

- *Site Information* pertains to a description of the topography, soil, geology, and hydrogeology of the site as determined by a site assessment. Applicants are required to conduct a site assessment for all waste management facilities. For some facilities, applicants will also be required to design and implement a groundwater monitoring program based on the site assessment information. Refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection.*

- *Development Information* pertains to public consultation which includes obtaining approval from the local authority for the proposed development, as well as informing the public about the proposed facility and giving them the opportunity to communicate any concerns. Companies are encouraged to begin public involvement and communication activities well before submission of any application to the EUB. Refer to EUB Informational Letter, IL 89-4, *Public Involvement in the Development of Energy Resources.*

- *Closure Information* includes an estimate of the expected lifespan of the facility, a plan to close the facility during any point of its operational lifetime, and a financial assurance program to cover the estimated cost of closure activities. Refer to Section 20.0, *Financial Security,* and EUB IL 96-3, *Suspension and*

Reclamation of Upstream Oil and Gas Facilities, and the attached MOU that outlines the agreement reached between AEP and EUB on these activities.

In addition to the general information, the applicant must address the design and operation of waste management and disposal method(s) proposed for the facility, as listed in Sections 22.0 to 28.0.

Other application considerations include:

- Three copies of the application must be submitted to the Applications Groups within the Facilities Division of the EUB.
- All applications will be registered and the applicant will be invoiced for the registration fee. If the application is deficient or incomplete, it will be returned to the applicant.
- The level of detail in any application should reflect the scope and complexity of the proposed development.
- The licensee, approval holder, applicant or owner shall retain, for the life of the facility, copies of the details of their application, and verification that the as-built characteristics of the facility comply with the required design criteria, and make this information available to EUB staff upon request.

19.0 Environmental Impact Assessments

The EUB believes that oilfield wastes must be regulated in a manner that is equivalent to the way industrial wastes are regulated under the Environmental Protection and Enhancement Act (EPEA). Therefore, an applicant proposing to construct and operate an oilfield waste management facility may be required to prepare an Environmental Impact Assessment (EIA) report on the project, especially if dangerous oilfield wastes are to be handled.

Applicants proposing to construct and operate or to utilize the following methods to treat or dispose oilfield waste, are required to contact Alberta Environmental Protection (AEP) and the EUB to determine the need for an EIA:

- a fixed incinerator that accepts dangerous oilfield waste, and
- a landfill that accepts dangerous oilfield waste.

This communication should be done early in the process, before the application for the oilfield waste management facility is filed with the EUB.

As the characteristics that designate a waste regulated under EPEA as hazardous, are the same as those that classify oilfield waste as dangerous, the requirement to consult with AEP and the EUB regarding the need for an EIA is also extended to other proposed facilities that are intended to handle, treat, or dispose dangerous oilfield waste.

Enquiries regarding the EIA process should be directed to AEP, EIA Review Branch Head. The Director of Environmental Assessment will determine if further consideration for a proposed activity is needed under the Environmental Assessment process as outlined in EPEA under Part 2, Division 1, Environmental Assessment (Mandatory and Exempted Activities) Regulation AR 111/93 and Environmental Regulation AR 112/93. The characteristics of the proposed activity and the wastes associated with it will be considered by the Director in deciding if assessment under EPEA is needed.

If AEP decides that an EIA is required, the EIA report should be filed with the application to the EUB for the proposed facility.

20.0 Financial Security

20.1 Introduction

The **purpose** of this section is to provide information regarding financial security requirements for oilfield waste management facilities.

The EUB has identified the need for a financial security system for oilfield waste management facilities regulated by the EUB. Financial security is required to ensure adequate resources will be available for the eventual decommissioning and reclamation of these facilities.

Financial security will be required for each stand-alone oilfield waste management facility as well as for all EUB approved landfills and fixed thermal treatment facilities (excludes small batch feed and campsite incinerators).

The financial security system for oilfield waste management facilities will be administered by the EUB. The amount required will be based on the estimated cost of reclamation and the associated post-closure monitoring of the facility (as described in the closure portion of the initial application). The EUB requires that each oilfield waste management facility have its own financial security in place.

20.2 Facilities Requiring Financial Security

The following oilfield waste management facilities require financial security:

- oilfield waste storage facility,
- oilfield waste transfer station,
- surface facilities associated with disposal wells that require approval as outlined in Part D, Section 13.0, *Surface Facilities Associated with Waste Disposal Wells*,
- oilfield waste processing facilities,
- all EUB approved oilfield landfills,
- permanent biodegradation facilities (treats third party waste or are on a stand-alone site), and
- fixed thermal treatment facilities other than small batch feed and campsite incinerators.

In some cases, oilfield waste management components will be incorporated onto an existing approved oil and gas or oil sands facility site. Costs of closure of these waste management components will be included in the overall closure of the facility, and therefore, with the exception of landfills and fixed thermal treatment facilities other than small batch feed and campsite incinerators, financial assurance will not be required.

Waste treated by the waste management component must be generated on the site where the component is located, or if the component is located in a battery or gas plant, wastes can be accepted from associated well sites provided the well sites have the same licensee as the site on which the component is located.

The following oilfield waste management components/options do **not** require financial security:

- oilfield waste storage area,
- land treatment (on-site, one-time)
- biocells or biopiles (on-site, see biodegradation section),
- campsite incinerators, and
- small batch feed incinerators (burn less than 10 tonnes per month).

In cases where a facility requiring financial security already has posted security through another mechanism (i.e. security posted under EPEA requirements), the licensee and/or approval holder is responsible to identify this duplication to the EUB. If it is determined that the facility in question already has sufficient financial security in place through another mechanism, the EUB will not require additional financial security.

20.3 Determination of Financial Security

Financial security is to be provided by the applicant of the oilfield waste management facility. The amount of financial security required will be established based on the closure information provided to the EUB as part of the initial application for an oilfield waste management facility. In the case of existing facilities, the amount can be established from information provided in the original application. The approval holder may be required to provide further closure and cost information if the original information is out of date or incomplete.

The following is a procedure for determining the amount of financial security required:

1. An estimate of the total cost for reclamation must be provided by the applicant as part of the initial application for approval. This must also include any costs associated with post-closure monitoring and reporting. For existing facilities the closure information provided in the original application may have to be updated and/or expanded.

2. The estimated costs will be reviewed by the EUB and through consultation with the applicant/approval holder, the amount of financial security will be determined.

3. The applicant will be required to post the required amount of security before approval to operate will be given.

4. In the case of existing facilities, once the EUB has determined the amount of security required, the applicant/approval holder will have **60** days to put the financial security in place in order to continue to operate.

20.4 Adjustment of Security

There are several situations which may affect the required amount of security, these include:

- changes in the cost of future reclamation requirements,
- changes in the operations of a facility (see below),
- the land or any portion of it is reclaimed at the facility (see below),
- the closure plan is amended, and
- any other circumstances that may affect the cost of reclamation.

Any of the above circumstances may require the approval holder to reassess the amount of required security. The EUB expects that the operator will undertake this reassessment on an as-needed basis.

Adjustments will also be required on an annual basis to account for inflation as per the current annual Alberta Inflation Rate (Statistics Canada). For interest bearing securities where the interest is enough to cover the inflation rate, this will be considered adequate.

The EUB may also increase or decrease the amount of security required to reflect the current closure and post-closure costs. In the case where the EUB has increased the security amount, the facility approval holder will have **60** days to comply. In the case where the amount is decreased, the facility approval holder can modify the specific facility security.

Additionally, the approval holder may apply to the EUB to have their closure plans and associated costs adjusted based on changing site conditions, operating procedures, etc. The approval holder must make this request in writing.

The financial security process to be followed when facilities are built, purchased, sold, or changed is as follows:

1. New Facilities

Approvals for new facilities will be contingent on the approval holder posting adequate financial security prior to the start-up of the facility. The amount of the security is based on the cost of closure specified in the application and approved by the EUB.

2. Facilities Undergoing Expansion/Changes

Changes to the closure plan must be submitted as part of an application for modification of the facility. The plan must include amendments to the closure and post-closure cost with the expansion/changes in place. Depending on the amount of security that the changes represent, the EUB will decide whether adjustments are required immediately or can be deferred until the next security anniversary date.

3. Facilities Undergoing Closure

Following the confirmation from AEP that the clean-up objectives for the next intended land use have been achieved, the EUB will notify the approval holder that the amount of security required for that facility will be reduced accordingly. It should be noted that the amount required for post-closure monitoring, if required, may be held back to ensure that the monitoring is conducted.

4. Facilities Which are Sold or Transferred

The financial security for the approval holder selling the facility will not be returned until the approval for transfer is given by the EUB. The purchasing company will be required to post security for this facility before the approval will be transferred.

20.5 Acceptable Forms of Security

Security must be in one or more of the following forms payable to the EUB:

- cash,
- irrevocable letters of credit, performance bonds or security bonds in a form acceptable to the EUB, or
- any other form acceptable to the EUB.

20.6 Forfeiture of Security

Security provided for a facility may be forfeited if the operator/approval holder:

1. fails to commence and complete reclamation in a timely fashion at the facility,
2. fails to meet reclamation standards specified in the closure plan,
3. fails to renew an existing security before its expiry date or fails to adjust the security amount for inflation (refer to Section 20.7, *Renewal of Security*),

4. fails to account for changes in the closure plan,

5. has not complied with an order or direction of the EUB or AEP, or

6. becomes insolvent.

The EUB will provide prior notice to the operator of its intention to collect on the security for reasons identified in points 1, 2, 4, and 5 above.

The forfeited security is held by the EUB in an interest bearing trust account. Interest earned less administrative fees will be added to the security. The funds will be used to reclaim and perform post-closure monitoring of the facility(s) in question as well as to pay any administrative fees. If any money remains in the security after the reclamation and post-closure monitoring of the facility(s) has been completed, the EUB will pay the excess amount back to the approval holder of the facility(s). Where the amount of the forfeited security and interest is insufficient to pay for the cost of the reclamation and post-closure care of the facility(s) including administrative fees, the approval holder remains liable for the balance.

20.7 Renewal of Security

For securities with expiry dates, the EUB requires replacement securities to be in place **30 days** prior to the expiry of the previous security (new security must account for inflation).

For securities with no expiry date, adjustments to account for inflation must also be in place **30 days** prior to the anniversary date of the security.

The EUB expects the approval holder to keep track of renewal dates.

The EUB will not notify approval holders when securities are due to be renewed. If the new/adjusted security is not put in place, the EUB will collect the present security and subsequently notify the approval holder of this action (see Section 20.6, *Forefeiture of Security*). If a suitable security is put in place at a later date, the approval holder may apply to the EUB for a return of any money not used for reclamation and post-closure monitoring back to the approval holder, less administrative fees.

21.0 General Information Required in Applications

The **purpose** of this section is to identify the general information that is required in all applications to construct and operate an oilfield waste management facility. In addition, specific application information is required as per Sections 22.0 to 28.0.

21.1 Application Introductory Information

The following introductory information shall be provided:

(a) date of application,

(b) name, address, and phone number of the applicant,

(c) name, address, and phone number of the operator (if different from above),

(d) the name of the facility,

(e) the legal land description of the facility site,

(f) current land use and zoning,

(g) proposed construction commencement and completion date,

(h) proposed date of commencement of operations,

(i) a discussion of the applicant's technical and financial qualifications that are pertinent to the design, construction, and operation of any part of a waste management facility,

(j) a list of the sections that will be included in the application (waste storage, transfer station, surface facility associated with a waste disposal well, waste processing, landfill, biodegradation, thermal treatment, and other), and

(k) an indication of whether an application for a waste disposal well or a cavern that will be associated with the project proposed in this application has been submitted to the EUB.

21.2 Assessment Information

To assess the impact and necessity of the proposed facility the applicant shall, where applicable, provide:

(a) a general description of the proposed facility,

(b) an analysis of the need for the facility including:

(i) the geographical area the facility will service and the streams that will be accepted (include whether the facility is intended to handle wastes generated only by the applicant, (i.e. first party), or wastes generated by various companies; (i.e. third party),
(ii) historical statistics and production forecasts for oilfield wastes in the area, and
(iii) the technical, environmental, and economic benefit of building a new facility,

(c) the criteria used to select the proposed site, as well as any alternative sites considered,

(d) a description of the potential positive and negative environmental, social, economic, and cultural impacts of the proposed facility,

(e) the plans developed to mitigate and monitor the potential negative impacts identified,

(f) the plans developed to minimize the production or release into the environment of substances that may have an adverse effect,

(g) a response indicating whether the Director of Environmental Assessment has determined if an EIA is necessary for the proposed facility, or a response describing the reasoning the applicant used to determine that an EIA was not necessary, and

(h) any other information the EUB may require.

21.3 Site Information

A concise summary outlining the information obtained from the site assessment (refer to Appendix 4.0, *Requirements for Site Assessment and Groundwater Protection*). This concise summary must include:

(a) a facility plot plan at an appropriate scale that clearly identifies:

(i) site topography, surface drainage patterns, local recharge and discharge areas, type of vegetation, and tree cover,
(ii) on-surface or buried pipelines, utility lines, conduits, pits, or tanks,
(iii) buildings, loading facilities, or storage areas,
(iv) disposal or source wells,
(v) existing or abandoned monitoring wells or standpipes,
(vi) any areas containing buried fill material or waste,
(vii) any areas of known extensive or frequent spills, and
(viii) horizontal direction of shallow groundwater flow,

(b) the location of all surface waters and inferred areas of groundwater discharge within a 3 km radius of the site,

(c) a summary of local groundwater and surface water users within a 3 km radius of the site,

(d) a summary of the regional hydrogeology and geology for the area in which the site is located as derived from existing data in the public domain,

(e) the description of the soil including the following:

  (i) the physical characteristics of the soil including thickness, texture, internal drainage characteristics, evidence of fracturing, and an estimate of the moisture content, and
  (ii) the background chemical characteristics of the soil, including pH, electrical conductivity, major extractable ions, cation exchange capacity, total metals, per cent hydrocarbon, and sodium adsorption ratio,

(f) a description of how the quality of the surface and subsurface soil will be monitored,

(g) for those facilities that require groundwater monitoring, site specific information as determined during the drilling and installation of monitoring wells, including the following:

  (i) the description of the surficial geology, including the type and thickness of strata,
  (ii) the depth of the shallowest water bearing strata (depth of the water table) and the hydraulic conductivity of this zone, including raw test data and method of analysis,
  (iii) the horizontal and vertical directions, rates, and approximate velocities of the groundwater flow,
  (iv) a description of the quality of the groundwater including, as a minimum, the initial results obtained for pH, electrical conductivity, major ions, total metals, and mineral oil and grease,
  (v) the depth, location, and type of any contaminant encountered, the probable source of the contaminant, and acknowledgement that AEP has been contacted regarding the contamination,
  (vi) the rationale for the location, depth, and screened interval for each monitoring well,
  (vii) a description of the construction materials and completion details for each well,
  (viii) methods employed to develop the wells,
  (ix) sampling and testing procedures, and
  (x) the ground level elevation, casing top elevation, depth to water, depth of well, and screened interval for each well, presented in a tabular form,

(h) a description of how the surface run-off water will be controlled, accumulated, and discharged including, if applicable, the pond or dike design and sizing calculation for containment of a 1 in 10 year, 24-hour storm, and the path taken by the surface run-off discharge,

(i) a description of how the quality of the ambient air will be monitored, and

(j) any other information the EUB may require.

21.4 Development Information

Information relating to the development of the site shall, where applicable, include:

(a) written confirmation indicating that the landowner has consented to the construction and operation of the facility,

(b) verification that approval (a development permit) from the local authority has been obtained or is in the process of being obtained,

(c) a description of the consultative process undertaken to inform the public of the proposed development in accordance with EUB IL 89-4, *Public Involvement in the Development of Energy Resources* including:

  (i) the names of the landowners/occupants personally contacted within a 0.5 km radius of the proposed facility and any concerns they had regarding the proposed development,
  (ii) a copy of the information package delivered to all landowners/occupants within a 1.5 km radius of a proposed sweet facility and a 2.0 km radius of a proposed sour facility, or to any interested party, as well as any resulting concerns about the proposed development, and
  (iii) a map showing the landowner/occupant of all lands within a 1.5 km (sweet) or 2.0 km (sour) radius of the facility, and

(d) any other information the EUB may require.

21.5 Closure

A discussion regarding closure of the facility shall, where applicable, include:

(a) a description of the plan developed to perform any planned or unplanned closure of the facility, or any part of it, at any point during its active life including:

  (i) an estimate of the maximum inventory (wastes and products) expected on-site and how these inventories will be eliminated,
  (ii) an estimate of the time required to eliminate inventories, and

(iii) a schedule of closure activities including the elimination of inventories, the dismantling of surface equipment, the abandonment of wells or pipelines, and the reclamation of the facility site,

(b) a description of the proposal developed for post-closure monitoring if required,

(c) an estimate, in current dollars, of the cost of planned or unplanned closure and of post-closure monitoring or site maintenance,

(d) the financial assurance the applicant can demonstrate to cover the cost of facility closure and post-closure care (refer to Section 20.0, *Financial Security*),

(e) an estimate of the expected year of final closure of the facility,

(f) the expected land use and zoning of the site after effective closure, and

(g) any other information the EUB may require.

22.0 Waste Storage Facilities and Transfer Stations - Specific Application Information

The **purpose** of this section is to identify the specific information which is required in an application to construct and operate a waste storage facility or transfer station.

General information, which is also required with the application, is contained in Section 21.0.

For operational information, reference should also be made to Part D, Section 12.0, *Waste Storage Areas/Facilities and Waste Transfer Stations*.

22.1 Design and Operational Procedures

Details on the design features and operational procedures shall, where applicable, include:

(a) a description of the oilfield waste streams that will be accepted for storage including their source and anticipated annual volumes,

(b) a description and scale diagram of the facility design in accordance with EUB ID 95-3 and Guide G-55, *Storage Requirements for the Upstream Petroleum Industry*, including:

  (i) the location, size, and construction material of all storage containment devices, including the materials to be stored within,
  (ii) the secondary containment system and its capacity,
  (iii) the leak detection system and the sampling program established for it, including the sampling frequency and the parameters the samples will be tested for,
  (iv) if applicable, the corrosion monitoring system,
  (v) the management or control of inventory to minimize spills or overflows, and
  (vi) the location, size, and equipment spacing of all heating, pumping, and compressing equipment.

(c) a description of the operational procedures including:

  (i) the method of receiving, appropriately segregating, storing, and handling the various oilfield wastes,
  (ii) the estimated retention time of the various oilfield wastes in the facility, and
  (iii) the method of removing and transporting oilfield wastes to an approved facility for treatment and/or disposal, and the name of the treatment/disposal facility,

(d) a description and example of the method in which material balances will be kept, identifying receipt to disposition of all waste materials,

(e) a description of the security measures with respect to unauthorized dumping or entry by unauthorized persons, livestock, or wildlife,

(f) a description of the operational safety procedures in place, as well as the contingency plan developed to respond to emergencies such as fires or the accidental release of fluids or fugitive air emissions,

(g) the qualifications with respect to training and certification required by employees, and

(h) any other information the EUB may require.

23.0 Surface Facilities Associated with Waste Disposal Wells - Specific Application Information

The **purpose** of this section is to identify the specific information which is required in an application to construct and operate a surface facility associated with a waste disposal well.

General information, which is also required with the application, is contained in Section 21.0.

For operational information, reference should also be made to Part D, Section 13.0, *Surface Facilities Associated with Waste Disposal Wells.*

Operators seeking approval for a waste disposal well should first refer to EUB IL 94-2 and EUB Guide G-51 for completion, logging, testing, monitoring, and application requirements. These references identify the types of wastes that can be injected down the various classes of disposal wells. Guide G-51 does not, however, outline the requirements for any surface facilities associated with the well. Therefore, operators applying for approval of a Class Ia or Ib waste disposal well that will not be located on an existing EUB approved site, but will have surface facilities (i.e. receiving tanks) associated with the well, will be required to include the information outlined in this section on surface facilities, in the application for the disposal well. Whenever possible, a joint approval will be given for both the disposal well and the surface facilities.

23.1 Design and Operational Procedures

Details on the design features and operational procedures shall, where applicable, include:

(a) a description of the oilfield waste streams that will be accepted for deep well disposal, including their source and anticipated annual volumes,

(b) a description and scale diagram of the surface facilities associated with the disposal well in accordance with EUB ID 95-3 and Guide G-55, *Storage Requirements for the Upstream Petroleum Industry*, including:

- (i) the location, size, and construction material of all storage containment devices,
- (ii) the secondary containment system and its capacity,
- (iii) the leak detection system and the sampling program established for it, including frequency and the parameters the samples will be tested for,
- (iv) if applicable, the corrosion monitoring system,
- (v) the tank inventory control systems to minimize spills or overflows, and
- (vi) the location, size, and equipment spacing of all, heating, pumping, and compressing equipment,

(c) a description of the operational procedures including:

(i) the method of receiving the wastes, and for those Class Ia wells approved to accept industrial as well as oilfield wastes, the method used to segregate the wastes, and acknowledgement that AEP has approved the industrial waste streams, the surface facilities used to receive them, and the plan developed to manage any residuals (solids or organics) that separate from the fluids, and

(ii) the method of removing residuals, such as oil or solids that separate from the upstream waste fluids and the method used to treat or dispose the residuals including the name of the treatment/disposal facility,

(d) a description and example of the accounting procedures from the receipt to disposition of all materials. This description shall include, but not be limited to:

(i) the methods used to verify the composition and volume of incoming materials,

(ii) the procedure used to measure and account for all fluids injected into the well, and

(iii) the procedure used to measure and account for all fluids injected into the well and any crude oil recovered from the upstream side,

(e) a description of the security measures with respect to unauthorized dumping or entry by unauthorized persons, livestock, or wildlife,

(f) a description of the operational safety procedures in place, as well as the contingency plan developed to respond to emergencies such as fires or the accidental release of fluids or fugitive air emissions,

(g) the qualifications with respect to training and certification required by employees, and

(h) any other information the EUB may require.

24.0 Waste Processing Facilities - Specific Application Information

The purpose of this section is to identify the specific application information which is required in an application to construct and operate a waste processing facility.

General information, which is also required with the application, is contained in Section 21.0.

For operational information, reference should also be made to Part D, Section 14.0, *Waste Processing Facilities.*

24.1 Design and Operational Procedures

Details on the design features and operational procedures shall, where applicable, include:

(a) a description of the oilfield wastes that will be accepted for processing or treatment and their anticipated annual volumes,

(b) a description of the treatment and process technologies to be used including the specifications of the receiving, inlet measuring, treating, separating, and recycling equipment, and their minimum and maximum flow capacities, retention times, and operating pressures and temperatures. For those facilities that have an integrated custom treating facility, identify any common and unique equipment,

(c) an estimate of the annual volume of freshwater to be used in the operation of the facility and the fresh water source, including where applicable, a copy of the groundwater diversion permit or water withdrawal permit,

(d) a process flow schematic showing:

(i) all the separation vessels, measurement points, vessel relief valves and piping, vessel drains, and fuel lines, etc.,
(ii) the minimum and maximum operating pressures and temperatures for each vessel, and
(iii) the common and separate equipment for those facilities that will include a custom treating facility,

(e) a scale diagram showing:

(i) the location, size, and equipment spacing of all separating, heating, pumping, and compressing equipment, including those common or unique to an integrated custom treating facility, and
(ii) the location, size, and construction material of all storage facilities and dikes, including those common or unique to an integrated custom treating facility,

(f) a description of the plans developed to monitor any leakage from tanks and other containment devices including, where applicable:

(i) the leakage monitoring system, including sampling frequency and test parameters,
(ii) the corrosion monitoring system, and
(iii) the management or control of tank inventory to minimize spills or overflows,

(g) a discussion of the method proposed for the disposal of solid waste and sludge material (for off-site disposal identify the operator, name, and location of the facility that will be used),

(h) a discussion of the method proposed for the disposal of liquid waste (for off-site disposal identify the operator, name, and location of the facility that will be used),

(i) a description and example of the accounting procedure from the receipt to disposition of all products. This description shall include, but not be limited to:

(i) the methods used to verify the composition and volume of the incoming streams, and
(ii) the procedure used to measure and account for any recovered oil, water, and solids. (Note: Oil recovered from an integrated custom treating facility must be accounted separately from the oil reclaimed from the wastes.), and

(j) any other information the EUB may require.

25.0 Oilfield Landfills - Specific Application Information

The **purpose** of this section is to identify the specific information which is required in an application to construct and operate an oilfield landfill.

General information, which is also required with the application, is contained in Section 21.0.

An application to construct or expand an oilfield landfill must address each of the requirements listed in Part D, Section 15.0, *Oilfield Landfills*, with regard to:

- Landfill Siting Criteria,
- Design Requirements,
- Operating Procedures,
- Required Engineer Features of Class Ia, Ib, II or III Oilfield Landfills,
- Waste Criteria,
- Monitoring and Analyses,
- Reporting Requirements, and
- Closure, Post-Closure and Reclamation Requirements.

25.1 Design and Operational Procedures

In addition to the above information, an application to construct or expand an oilfield landfill must also clearly state the following infomation based on the class of oilfield landfill being applied for:

(a) the Class of the proposed oilfield landfill, and whether third party wastes will be received by the landfill,

(b) a description of the oilfield waste streams to be placed in the landfill, including their source, and anticipated annual volumes,

(c) a description of the on-site waste handling methods,

(d) the method for measuring and accounting for the volumes of waste received,

(e) a description and discussion of the type of landfill design being proposed (above ground, shallow entombed or conventional),

(f) a description and discussion of the landfill development method being proposed cell, trench or area,

(g) the method for placing the waste into the landfill,

(h) a plot and schematic cross-section of the proposed landfill, including the location of the trench or cell in relation to the seasonal high water table,

(i) a description of the physical and chemical properties of any engineering containment systems (liners), and all other material underlying the landfill, including surficial deposits and bedrock, as well as a discussion of the ability of these materials (natural or installed) to retard the movement of contaminants and their compatibility with the oilfield wastes being landfilled,

(j) a description of the above-liner leachate control and handling system, including the monitoring protocol, testing frequency, and disposal destination of the leachate,

(k) a description of any below-liner leak detection system, including the monitoring protocol, and testing frequency,

(l) a description of the surface run-off and run-on control systems,

(m) an outline of any proposed gas interception, venting or recovery systems, and a description of how odours and fugitive emissions will be monitored, handled, and mitigated,

(n) a description of all proposed cover material including physical, and chemical properties,

(o) a description of the quality assurance and quality control methods to be employed to ensure proper site engineering and installation practices are followed, including a description of how the hydraulic conductivity and integrity of all liners will be verified during construction,

(p) a description of the security measures with respect to entry by unauthorized persons, livestock or wildlife, or with respect to unauthorized dumping,

(q) a description of the operational safety procedures in place, as well as the contingency plan developed to respond to emergencies such as fires or fugitive air emissions,

(r) the qualifications with respect to training and certification required by employees, and

(s) any other information the EUB may require.

25.2 Reclamation Plan

A reclamation plan, laid out during the initial design of the landfill and incorporated throughout the operational life of the landfill, shall include:

(a) a description of the reclamation design and proposed post-reclamation use of the landfill site,

(b) a description of how this design was incorporated into the initial site assessment, and how it will be incorporated into the overall operation of the landfill,

(c) a description of how the leachate collection, leak detection, groundwater monitoring, and gas interception, venting or recovery systems will continue to be maintained and operated, and

(d) any other information the EUB or AEP may require.

26.0 Biodegradation Facilities- Specific Application Information

The **purpose** of this section is to identify the specific application information which is required in an application to construct and operate a biodegradation facility.

General information, which is also required with the application, is contained in Section 21.0.

For operational information, reference should also be made to Part D, Section 16.0, *Biodegradation*.

26.1 Design and Operational Procedures

Details on the design features and operational procedures shall, where applicable, include:

(a) a description of the oilfield wastes to be accepted for biodegradation including their source, anticipated annual volumes, and typical chemical and physical characteristics,

(b) a description of the proposed biodegradation technique including the volume that will be treated at one time, any amendments that will added, and the anticipated degradation period for a volume of waste,

(c) a description and example of the accounting procedure from receipt to disposition of all products.

(d) a description of the intended uses or disposition of the treated material,

(e) a description of how any generated leachate will be handled and/or disposed,

(f) a description and scale diagram of the design of the biodegradation system including:

- (i) the primary containment device,
- (ii) the secondary containment device,
- (iii) the leachate collection system,
- (iv) the leak detection system, and
- (v) the groundwater monitoring system, if applicable,

(g) a scale diagram of the facility site showing the following in relationship to the biodegradation system:

- (i) location, size, and equipment spacing of any separating, heating, pumping, and compressing equipment, and
- (ii) location, size, and construction of any storage facilities,

(h) a description of how fugitive air emissions will be monitored,

(i) a description of the operational safety procedures in place at the facility, as well as the contingency plan developed to respond to emergencies such as fires, the accidental release of fluids, or fugitive air emissions,

(j) the qualifications with respect to training and certification required by employees,

(k) a description of the security measures with respect to unauthorized dumping or entry by unauthorized persons, livestock, or wildlife, and

(l) any other information the EUB may require.

27.0 Thermal Treatment Facilities - Specific Application Information

The **purpose** of this section is to identify the specific application information which is required in an application to construct and operate a thermal treatment facility.

General information, which is also required with the application, is contained in Section 21.0.

For operational information, reference should also be made to Part D, Section 17.0, *Thermal Treatment.*

27.1 Design and Operational Procedures

Based on the thermal treatment technology (incineration or thermal desorption) being applied for, details on the design features and operational procedures shall, where applicable, include:

(a) a description of the oilfield waste streams that will be accepted for thermal treatment including their source, characterization, composition, and anticipated annual volumes,

(b) a description of the design and manufacturer's specifications of the incinerator including the make, model, number, chamber type, rated capacity, and charging method,

(c) the limiting design and operating values of the parameters, if applicable, listed below and a discussion of why the identified limits apply:

- (i) primary chamber temperature, pressure, design volume, and hearth area,
- (ii) secondary chamber temperature, pressure, and retention time,
- (iii) primary air injection,
- (iv) secondary air injection,
- (v) auxiliary burner(s) type, primary ignition, secondary afterburner, timer cycle, supply fuel, and type of flame failure control,
- (vi) minimum destruction and removal efficiency,
- (vii) combustion performance parameters including minimum oxygen level, maximum carbon monoxide levels, and minimum incinerator operating temperature, and
- (viii) stack emission levels for opacity, hydrogen chloride, particulate, dioxin and furan, carbon monoxide, carbon dioxide, nitrogen oxides, and sulphur dioxide,

(d) a description of the incinerator stack including its diameter, height above grade, height above roof, distance from the nearest building and the building's height, height of other obstructions, spark arrester, sampling ports provided, and pollution control equipment,

(e) a description of process monitoring system for the incinerator and of the continuous emissions monitoring system for the stack,

(f) a scale drawing of the incinerator showing its internal dimensions, burner locations, charging doors, size and location of test openings, temperature control, and temperature recording device,

(g) a description of the testing to be conducted to ensure the required destruction and removal efficiencies and emission limits will be met,

(h) a description of the operational procedures including:

 (i) the method of receiving, storing, and preparing waste for incineration,
 (ii) a list of the gaseous and particulate substances and their volumes that will be released into the environment as a result of the incinerator's operation, as well as the methods by which the substances will be released and the operational steps taken to reduce the volumes released, and
 (iii) a discussion of the method proposed for the disposal or treatment of the liquid and solid residue or ash generated by the incinerator,

(i) a scale diagram of the facility showing the location, size, and material specification of all equipment and surface improvements,

(j) a description and example of the accounting procedure from receipt to disposition of all products,

(k) a description of the operational safety procedures in place at the facility, as well as the contingency plan developed to respond to emergencies such as fires or fugitive air emissions,

(l) the qualifications with respect to training and certification required by employees,

(m) a description of the security measures with respect to unauthorized dumping or entry by unauthorized persons, livestock, or wildlife, and

(n) any other information the EUB may require.

28.0 Other Waste Management Technologies

Applicants wishing to apply for an oilfield waste management technology not described in the previous sections shall provide information on the design features, operational procedures and monitoring systems applicable to the waste management technology. The details provided should reflect the scope and complexity of the proposed development.

PART F

OTHER WASTE MANAGEMENT

AND

DISPOSAL OPTIONS

Part F

OTHER WASTE MANAGEMENT AND DISPOSAL OPTIONS

29.0 Spreading of Oily By-Products to Roads

29.1 Introduction

The **purpose** of this section is to establish the minimum requirements and criteria for applying oily by-products materials to road surfaces.

The **intent** of these requirements is to ensure that environmental considerations surrounding the safe and responsible application of oily by-products to road surfaces are addressed.

Approval holders or licensees of oil and gas facilities must maximize the recovery and conservation of resources and minimize the amount of oily by-product material generated. Licensees and approval holders producing this material are strongly encouraged to review their respective handling and disposal techniques in consideration of alternate oil reclamation programs. Good operating practices used in the management of storage facilities for oily by-products such as minimizing the volumes of produced water and other oilfield wastes entering these facilities. The removal of free water will greatly assist in meeting the criteria set out in this section.

The EUB considers the application of oily by-product materials to public or private roads as an acceptable management option available to the oil and gas industry. The oily by-product materials, which are typical of that recovered or generated during in-situ oil sands and heavy oil production operations in northeast Alberta, is a resource valued by local communities when applied to permanent roads in accordance with criteria set out in these requirements. A joint industry, government, and scientific task force has been investigating and researching this matter for many years. Their research has shown that if applied appropriately, this material poses minimal environmental impact and safety risks.

The use of oily by-products in agricultural product storage areas, feed lots, or temporary lease roads is prohibited.

29.2 Oily By-Product Materials

Oily by-product material is considered materials containing oil or bitumen generated during heavy oil production and typically consists of mainly sand and slop oil.

29.3 Characterization

Oily by-product material may be applied to road surfaces if the following characterization criteria are met:

1. No free water. Every effort should be made to ensure water on the surface or lying within the storage facilities is recovered prior to removing the oily by-product material for application to roads.

2. Oil shall be of a density greater than 920 kg/m^3. Material with less than 5 per cent residual hydrocarbon is unacceptable as road mix.

3. pH ≥ 6.

4. Total salts (calculated as a loading limit):

   - Na ≤ 5 500 kg/ha, and
   - Cl ≤ 7 000 kg/ha.

5. Total metals (concentration in sample):

   - Cd ≤ 3 mg/kg,
   - Hg ≤ 0.8 mg/kg,
   - Pb ≤ 375 mg/kg,
   - Ni ≤ 150 mg/kg,
   - Cu ≤ 150 mg/kg, and
   - Zn ≤ 600 mg/kg.

   Note: The above metal concentrations have been derived from the CCME Criteria for metals in agricultural applications. They are intended to be used as a **screening tool or flag**. The limits will be used to assess whether the metal concentrations as derived from the analytical methodologies are within the expected limits for those metals. If metal concentrations are noted in excess of the above limits, the licensee and/or approval holder of the oil and gas facility may be asked to provide an explanation prior to approval being granted. Licensee and/or approval holders who repeatedly exceed the limits will be required to carry out a detailed investigation as to the cause.

6. The material must not contain halogenated hydrocarbons, hazardous chemicals, refined or lube oils, drilling waste, flare pit sludges, or deleterious substances such as filters, rags, vegetation, or other debris including significant volumes of contaminated agricultural soils.

29.4 Application Depth

The maximum depth of application of material is limited to the smallest of the "Calculated Application Depths" determined for Na and Cl using the following formula:

$$d\ (cm) = \frac{L \times 10^4}{D \times C}$$

where:

- d = depth (cm) - calculated.
- L = loading rate (kg/ha) - specified in Section 29.3(4) for Na and Cl,
- D = density of sample (kg/m^3) - determined by laboratory, and
- C = concentration Na and/or Cl (mg/kg) - determined by laboratory.

Note: Application method for oily by-product materials are set out in the Saskatchwan/Alberta Waste Disposal Cooperative report, *Alberta Recommended Practices for Road Surfacing and Dust Suppression Techniques* (revised July 1994). This report is available through EUB Field Offices. The amount of material that can be applied to roads, as calculated above, must also be consistent with that report. Industry must adopt these as minimum acceptable oily by-product application methods.

29.5 Mixing Of By-Product Materials

If the material to be used for road surfacing or dust suppression is a combination of two or more oily by-product streams (i.e. from a number of different storage facilities), each must be sampled and analyzed in accordance with the methods prescribed. The limiting factor for application of the aggregate material will be dependent on loading limits of Na and Cl noted in Section 29.4, *Application Depth,* assuming metals are within the established limits. Therefore, the limiting application depth of the oily by-product materials used in the final mix will be calculated as follows:

$$d\ (cm) = \frac{L \times 10^4}{(D1 \times C1 \times P1) + (D2 \times C2 \times P2)}$$

where: d = maximum application depth (cm) - calculated,
L = loading rate (kg/ha) - specified in Section 29.3(4) for Na and Cl,
D1 = density of first substance (kg/m^3) - determined by laboratory,
C1 = concentration Na or Cl (mg/kg) - in first substance determined by laboratory,
P1 = proportion of first substance in the final mixture,
D2 = density of second substance (kg/m^3) - determined by laboratory,
C2 = concentration Na or Cl (mg/kg) - in second substance determined by laboratory, and
P2 = proportion of second substance in the final mixture.

Example calculation from data sheet:

Notes	Sample #	Density (kg/m^3)	Concentration (mg/kg)	Calculated Depth of Application
Sand	1	1792	Na = 3300	9.30cm
	1		Cl = 5640	5.97 cm
Slop Oil	2	1052	Na = 3350	15.6 cm
	2		Cl = 6900	9.64 cm

Assume the mix will contain 70 per cent sand and 30 per cent slop oil by volume.

In this example, Cl is the limiting factor in both samples (5.97 cm in #1 and 9.64 cm in #2). If Na was the limiting factor in one sample and Cl in the other, the mixing depth calculation would have to be repeated for both Na and Cl. The smaller of the two calculated application depths would be the limiting factor for the composite mix.

Using the equation above :

d (cm) = 7000 kg/ha x 10^4 /{(1792 kg/m^3 x 5640 mg/kg x 0.70) + (1052 kg/m^3 x 6900 mg/kg x 0.30)} = 7.56 cm

The mix of 70 per cent sand and 30 per cent slop oil can be applied 7.6 cm deep.

29.6 Sampling

Appropriate sampling methods must be used to obtain a representative sample from each storage facility or container whose contents are to be used in the disposal project in question. Sub-samples from the field containers (usually 20L polyethylene pails) should be prepared following the protocol below:

- visually examine the sample, record ratio of free water to solids,

- decant and discard any free water in the sample container,
- remove all large rocks, twigs, or vegetation,
- homogenize the remaining oily by-product material, and
- collect a 2 kg aliquot of the homogenized sample and place in a clean glass jar (1 L) with a teflon-lined lid. Store the sample at 4°C. Collect sub-samples from the 1 L glass jar for the required analyses.

29.7 Analyses

The following analyses are required for the characterization of the oily by-product material:

METHOD	PARAMETERS
*1.9 (sample: water) Water Soluble Extract	pH, Specific Conductance, Chloride, Sodium
* Composition Analysis (Dean Stark)	% water, % solids, % hydrocarbon
* Total Metals (US EPA 3050 (SW 846))	cadmium, mercury, lead, nickel, copper, zinc
Specific Gravity (Standard Methods for the Examination of Water and Waste water, APHA, AWWA, WPCF, 16th Ed. Washington, 1985. Method 213 E.)	Density of oily by-products resembling sludges.
Specific Gravity (American Society for Testing and Materials, Washington. "Standard Method for Specific Gravity of Soils", Designation D 854 - 83).	Density of granular oily by-products such as oil sands and silts.

* A description of the unique analytical methods is included in this section. The remaining methods can be found in the cited sources.

A standardized reporting format has also been developed to ensure consistency in chemical analyses and units of measurement (see attached *Oily By-Product Characterization for Road Disposal Data Sheet*). Use this form to report all data.

1. 1:9 Water Soluble Extract Analyses Oily By-Product Material for Application to Roads (tentative)

This method as described specifically relates to water soluble extracts on oily by-product material which are being considered for application to roads, and is intended for the determination of pH, specific conductance, chloride, and sodium.

The sample is shaken with demineralized water at a 1:9 (sample: water) ratio for several hours and then allowed to stand overnight. Analyses are carried out on the clarified aqueous portion. Data are expressed as milligrams of constituent per kilogram of original material as received.

(a) Procedure

(i) Prepare a 1:9 (sample: water) mixture by weighing 100 grams, ± 0.1g (to an accuracy of ± 0.1g) of homogenized oily by-product material into a 2 litre glass jar with a teflon lined lid. Add 900 ml demineralized water.

(ii) Shake on a mechanical shaker for 2 hours.

(iii) Allow to stand overnight at 4°C.

(iv) Decant supernate - if supernate portion of sample is extremely turbid with suspended solids, clarification may be carried out by filtering supernate through a coarse (5 u) pure cellulose filter paper. Carry out pH and specific conductivity measurements on the supernate. Follow instrument manufacturers recommended procedures.

(v) Filter a portion of the supernate through 0.45 u cellulose accetate filter paper. Carry out chloride and sodium analyses on the supernate by Ion Chromatography and Atomic Absorption Spectrophotometry respectively, following manufacturers recommended procedures.

Note: Other approved analytical methodology may be used, such as titrimetric or colorimetric procedures for chloride determinations, and flame emission or Inductively Coupled Plasma Emmission for sodium determinations.

(b) Data Generation and Calculations

(i) Report pH values in pH units and Specific Conductance in dS/m on the liquid supernate.

(ii) Report chloride and sodium values in mg/L obtained from the liquid supernate and then calculate the concentration of these elements in mg/kg appearing in the original sample "as received" (i.e. mg/L (from supernate) x 9 = mg/kg).

(iii) Use the standard report form as supplied (see attached, *Oily By-product Characterization for Road Disposal Data Sheet*) to report all data.

(iv) Calculate the loading value for sodium and chloride in kg/ha by following the calculation as outlined on the data sheet. This provides a loading value in kg of constituent per hectare of road surface.

2. Dean Stark Analysis for Oily By-Products

Dean Stark analysis is used to determine the hydrocarbon, water, and solids contents of oily by-product samples by using a toluene reflux to separate these components. Condensed solvent and water are continuously separated in a distillation trap, with the water being retained in the trap. The solvent is recycled through the extraction thimble of the extraction apparatus to dissolve the hydrocarbon. The solids remaining in the thimble after extraction are measured gravimetrically, the water content is measured by volume in the trap, and the hydrocarbon content is calculated from this data.

(a) Apparatus

(i) Condenser - approximately 400 mm long with a 24/40 standard taper joint.

(ii) Distillation trap - with 24/40 standard taper joints, constructed so that the water is separated from the solvent, and the solvent is recycled back into the distillation apparatus.

(iii) Distillation flask - a 1 Litre 45/50 standard taper single necked flash.

(iv) Extraction Thimble - Whatman 85 x 200 mm cellulose thimble, single thickness.

(b) Procedure

(i) Dry the thimbles in the drying oven for a minimum of 8 hours. Cool the thimbles in the desiccator for a minimum of 20 minutes, weigh to the nearest 0.001 g. Record this weight as the initial dry weight of the thimble.

(ii) Ensuring that the sample is homogeneous, add approximately 30 to 40 g of sample to the thimble, weigh to the nearest 0.001 g. Record this as the weight of the thimble plus sample.

(iii) Assemble the distillation apparatus, ensure that all joints are vapour tight.

(iv) With water flowing through the reflux condensers, turn the hot plate or heating mantle to a medium heat setting, this will start the reflux.

(v) The toluene will boil and immerse the thimble in hot vapour. As the material in the thimble is heated, the water in the sample will be vaporized and be carried along with the hot solvent vapours to the condenser where they will be cooled and fall back into the distillation trap. The water will fall to the bottom of the trap, and the solvent will be recycled back into the distillation apparatus. The hydrocarbon portion of the sample will be dissolved in the hot solvent vapour, and drip from the bottom of the thimble.

(vi) The extraction is complete when the water level in the trap remains constant, and the solvent dripping from the thimble is clear. Depending on the nature of the sample, this may take from 1 to 8 or more hours.

(vii) Terminate the extraction and allow the solvent and apparatus to cool.

(viii) Measure the volume of water that is retained in the distillation trap to the nearest 0.1 ml. Record this volume as the volume of water.

(ix) Dismantle the distillation apparatus and remove the thimble.

(x) Dry the thimbles in the drying oven for a minimum of 8 hours. Cool the thimbles in the desiccator for a minimum of 20 minutes, weigh to the nearest 0.001 g. Record this weight as the final weight of the thimble.

(c) Data Generation and Calculations

$$\%\ Solids = \frac{S}{W} \times 100$$

$$\%\ Water = \frac{V}{W} \times 100$$

% Hydrocarbon = 100 - (% Solids + % Water)

Where: S = the final weight of the solids after the reflux is completed,
V = the volume of water retained in the trap, ml, the density of water is assumed to be 1.0 kg/L, and
W = the sample weight = (initial weight of thimble + sample) - (initial weight of the thimble).

- Use the standard report form as supplied (see attached *Oily By-product Characterization for Road Disposal Data Sheet*) to report all data.

3. **Acid Digestion of Sediments, Sludges, and Soils - US EPA 3050 (SW846)**

A representative 1-2 g (wet weight) sample is digested in nitric acid and hydrogen peroxide. The digestate is then refluxed with either nitric acid or hydrochloric acid. Dilute hydrochloric acid is used as the final reflux acid for the ICP or flame analysis of Cd, Pb, Ni, and V. Dilute nitric acid is employed as the final dilution acid for furnace AA analysis of Cd and Pb. A separate sample shall be dried for a solids determination.

(a) Procedure

Follow the EPA method with the exception of drying or grinding the sample prior to digestion.

(b) Data Collection and Calculations

(i) Calculate the concentrations for Cd, Hg, Ni, Cu, Zn, and Pb in mg/kg in the original sample "as received".

(ii) Use the standard report form as supplied (see attached *Oily By-product Characterization for Road Disposal Data Sheet*) to report all data.

29.8 Approval Process

1. Industry will sample and analyze the material to be spread on the roads or driveways.

2. If material is acceptable for road applications, the operator will provide the following information to the recipient (local authority or landowner) and the EUB:

(a) completed copy of the oily by-product characterization for road disposal data sheet signed by a representative from the laboratory and the operator, and

(b) a letter which identifies the source of the material and that it was sampled and analyzed properly and that it meets EUB requirements.

3. The operator shall have written consent that the recipient (local authority or landowner) agrees to have oily by-product spread on the road or driveway.

4. At the end of the season the EUB will enter the information onto the database and will provide a summary to the Counties and MDs. A copy of the program for the new database will be made available to the companies for their use. The company can maintain their own database and submit the information to the EUB on disk.

5. Each County and MD will submit a list of operators that have applied oily by-product to roads to the EUB.

6. The EUB will compare the database to the County and MD records and will follow-up any discrepancies.

Oily By-Product Characterization For Road Disposal Data Sheet

Laboratory Name: ______________________________

Lab Sample Number: ____________________ Date Received: ____________________

Field Sample Number: ____________________ Date Analysed: ____________________

Sample Information	
Company:	Source: (i.e. ecology pit, desand tank etc.)
Location: Lsd __ __ __ __ W M	Description: (i.e. oily sand, slop oil etc.)

Composition	(Dean Stark)	Extractable Salts	(1:9 Dilution)	
Oil	%	pH	SC	dS/M
Solids	%		Concentration	Calculated Depth of Application[2]
H_2O	%	Na mg/L	mg/kg	cm
Density of Sample	kg/m^3	Cl mg/L	mg/kg	cm

Total Metals (US EPA 3050 (SW 846))					
	Concentration		Concentration		Concentration
Cadmium/Cd	mg/kg	Nickel/Ni	mg/kg	Lead/Pb	mg/kg
Mercury/Hg	mg/kg	Zinc/Zn	mg/kg	Copper/Cu	mg/kg

Maximum application depth ____________ cm (least "Calculated Depth of Application" from above).

The undersigned hereby certifies that the information is accurate and in accordance with the requirements of Section 29.0.

Signed: ________________________ (Laboratory) ________________________ (Operator)

[1] Sample must not contain halogenated hydrocarbons, hazardous chemicals, refined or lube oil, flare pit sludges, or deleterious substances such as filters, rags, vegetation, and other debris including significant volumes of contaminated agricultural soils.

[2] The calculated depth of application for each constituent is determined as follows:

$$d\ (cm) = \frac{L \times 10^4}{D \times C}$$

Where:
d = depth (cm) - calculated
L = loading rate (kg/ha) - specified in Section 29.3 for Na and Cl
D = density of sample (kg/m^3) - determined by laboratory
C = concentration (mg/kg) determined by laboratory

This represents the calculated maximum depth of oil sludge (prior to mixing with aggregate) allowed, without exceeding each parameter limit specified in Section 29.3. Your maximum allowed application depth is the smallest of the two calculated values and total metals concentration must not exceed these values specified in Section 29.3. You must also follow the Recommended Standards of Practice.

30.0 Drilling Waste Management

For regulatory purposes, there are two categories of wastes produced from drilling operations:

- drilling sump wastes, and
- other solid, liquid material wastes associated with the wellbore and the surface equipment.

30.1 Drilling Sump Wastes

Drilling sump wastes are addressed in a separate EUB waste management document entitled *Drilling Waste Management Requirements* (Guide 50). The disposal and treatment protocols in this document are only applicable to drilling sump wastes and must not be applied to other oilfield wastes.

The *Drilling Waste Management Requirements* (Guide 50) were developed with comprehensive input and review from industry, government and the public sector under the direction of the Drilling Waste Review Steering Committee (DWRSC).

This included collective workshops and public participation.

30.2 Other Drilling Wastes

The management of the other drilling wastes is ultimately the responsibility of the well licensee.

31.0 Waste Transport by Pipelines

31.1 Introduction

The **purpose** of this section is to promote effective and operationally sound waste management practices that concern the disposal of waste into pipelines. Specifically, the use of pipelines as a conduit for waste dilution is discouraged. Although this concern primarily relates to crude oil pipelines, the information equally applies to natural gas pipelines.

Historically, crude oil pipelines have routinely been used for the disposal of a number of types of upstream petroleum industry wastes. These waste types include tank bottom sludges, lubricating oils, well servicing fracturing fluids, solvents, and other chemicals.

Although these wastes are often thought to be compatible with hydrocarbon liquids, operational problems have occurred in pipeline systems and downstream refineries from the cumulative effect of solids, metals, and other materials contained in the waste streams. It is now apparent that the current pipeline specification of less than 0.5 per cent BS & W (basic sediment and water) is singularly insufficient to control the quality of materials injected into pipelines, thereby potentially creating significant downstream waste management, process, and safety related issues.

As the authority to manage this subject does not fall under the jurisdiction of any one party, a committee was formed in 1994 representing refiners, producers, pipeline licensees, regulators, petroleum product suppliers, and waste facility operators.

31.2 Appropriate Wastes for Disposal via Injection into Pipeline Systems

It is recognized that the introduction of inappropriate wastes into crude oil pipelines is a waste management issue, as well as a crude quality issue which must be addressed between the producers, pipeline licensees, and refinery companies. It is expected that such issues will be routinely handled through contractual obligations between the parties involved.

Hydrocarbons in waste liquid (i.e. fracturing fluids) may be of value to refinery operations and under controlled conditions, may be safely handled by the pipeline and refinery system. The following oilfield wastes may be injected into a pipeline system if both of the following control conditions are met:

- the waste has a usable hydrocarbon content and does not pose a downstream handling problem, and
- specific agreements have been arranged between the waste producer, the pipeline licensee, and the refinery for which the specific waste volume is destined (refer to Section 31.3, *Communication*).

Appropriate Waste Types
(if the above two conditions are met:)

- Liquid pigging wastes.
- Certain hydrocarbon based drilling fluids.
- Certain hydrocarbon based surface and downhole treating chemicals.
- Waste refined fuels including diesel and gasoline.
- Well servicing fracturing fluids that are produced from the wellbore and are a part of regular production. Fluids transferred as part of a production stream will not require a specific agreement as identified above. Note: well servicing fracturing fluids, whether residual, spent or unused, which have purposely been isolated from the process production system (i.e. cannot be handled by surface separation or treatment usually due to solids content) must not be disposed directly into a pipeline system.
- Non-halogenated organic solvents. Note: if a solvent is contaminated then the control mechanism must address the contaminant, which may, in consultation with the pipelines and refineries, determine whether it is a contaminant to the pipeline and refinery system.
- Crude oil emulsions.
- The liquid component of all hydrocarbon based sludges provided it is not contaminated by any of the banned waste types, identified in Section 6.1.
- Certain other liquid hydrocarbon wastes that have a BS & W content greater than 0.5 per cent, but still have a sufficient hydrocarbon content to be acceptable, with agreement, by the pipeline licensee and refinery companies.

31.3 Communication

It is imperative that a cooperative communication process be established between producers, pipeline licensees, and refiners to successfully manage oilfield wastes and to help maintain the quality of Alberta's marketable crude oil.

Crude oil recovered from an oilfield waste treatment facility is not considered a waste as per these requirements. Other oilfield waste management facility products which are identified in the appropriate waste types list, are expected to be included in this communication process.

32.0 Radioactive Contaminated Oilfield Wastes

The **purpose** of this section is to establish the minimum requirements for the handling and disposal of radioactive contaminated oilfield wastes.

32.1 Control and Disposal of Recirculated Radioactive Contaminated Frac Sand

These materials are regulated by the Atomic Energy Control Board (AECB). Specific details on how radioactive contaminated frac sands are handled and disposed should be discussed with the AECB.

Licences issued by the AECB to all frac sand licensees normally contain the following condition:

For disposal, sand labelled with a radioactive prescribed substance shall be:

1. sent to Atomic Energy of Canada Limited, after making prior arrangement,
2. sent, after making prior arrangements, to a facility possessing an appropriate waste facility operating licence (WFOL) issued by the AECB, or
3. buried at the worksite under at least 30 cm of soil, provided that the specific activity is less than one scheduled quantity per kilogram of sand.

In all cases where the licensee uses the burial option, the contaminated material must be buried in accordance with the AECB licence condition.

If the licensee does not agree to burial in accordance with the disposal conditions of their licence, the AECB must be notified immediately of the following information:

1. the details of the job including:

   (a) site,
   (b) amount and type of tracer,
   (c) # of tonnes of sand used,
   (d) # of tonnes of sand recirculated,
   (e) where the sand is to be stored,
   (f) intended fate of the material,
   (g) soil conditions on the site, and
   (h) whether it was an oil or water based frac, and

2. the names of the people responsible for:

   (a) the well,
   (b) the contaminated sand,
   (c) the decision not to bury,
   (d) the transportation of the contaminated sand, and
   (e) the ultimate treatment or handling of the sand.

In certain cases, the AECB may, upon request, issue written approval for the transfer of oily, contaminated frac sand to a nearby site for burial where soil conditions are more suitable. The AECB views the transport of radioactive contaminated frac sand as an unnecessary hazard, subject to motor vehicle accident, containment leakage, and wind spreading, all of which could potentially result in contamination of public thoroughfares, private property, or equipment.

The following procedures are required by the EUB to handle and dispose radioactive contaminated frac sands:

1. If the material is to be buried on site, in accordance with the AECB licence, the material must be buried in clay.

2. If the material cannot be buried on site, the material must be disposed into an approved Class Ia or Ib landfill.

3. Oily by-product materials that contain radioactive materials may not be applied to road surfaces.

32.2 Naturally Occurring Radioactive Materials

Naturally Occurring Radioactive Materials (NORMs) are not within the scope of the Atomic Energy Control Act administered by the AECB. Jurisdiction for the control of NORM rests with the individual provinces.

The Western Canadian NORM Committee produced a document entitled *Guidelines for the Handling of Naturally Occurring Radioactive Material (NORM) in Western Canada.* These guidelines provide some general assistance on NORM management options. Not all these options are available in Alberta.

The options are very general in nature and do not give specific criteria for the handling treatment or disposal methods for the NORM material.

The EUB, together with stakeholders, will be developing specific NORM requirements. Until such time as these requirements are developed, the EUB recommends that any handling, treating, or disposing of NORM material generally follow the guidelines established by the NORM Committee document.

Copies of the NORM guidelines may be obtained from:

> Alberta Labour, Professional and Technical Services
> Occupational Health and Safety
> 9th Floor, 10808 - 99 Avenue
> Edmonton, Alberta T5K 0G5

PART G

APPENDICES

PART G

APPENDICES

Appendix 1.0

References

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Appendix 2.0

Definitions

Aboveground Storage Tank:	A tank that sits on or above the ground surface and whose top and complete external sides can be visually inspected.
Agent:	An agent is a person or corporation that assumes the same responsibilities and obligations as the applicant. An agent must be designated when the company seeking an approval does not have a corporate office in Alberta. An agent assumes all legal responsibilities for the applicant.
BS & W:	An acronym meaning "basic sediments and water" which commonly refers to settled solid and semi-solid components of liquids in tanks and other containment vessels. BS & W is also commonly referenced as S & W (sediments and water). BS & W or S & W are determined using the ASTM Standard D4007 or the API document *Sediment and Water*, Chapter 10, Section 3, Determination of Water and Sediment in Crude oil by the Centrifuge Method (Laboratory Procedure).
Biodegradation Facility:	Oilfield waste management facility utilizing biodegradation to degrade oilfield waste. Examples include permanent biopiles and biocells. On-site land treatment if a single application of oilfield waste is not considered to be a biodegradation facility.
Closure:	Occurs when there is no further disposal and/or treatment of waste at a waste management facility. Reclamation activities may still be ongoing after closure.
Closure (Landfill):	Occurs when there is no further disposal of waste at the landfill, and placement of a final cover is completed.
Compliance Test:	Evaluation of a thermal treatment process for the purposes of obtaining operational data to determine if a process meets the terms and conditions of regulatory approvals previously issued for that treatment process and the approved waste(s) tested. Requirements for compliance tests will be specified in the operating approval for the thermal treatment process.
Container:	Any portable above ground containment device (i.e. drums, pails, bags, boxes, totes, etc.) which has a capacity that does not exceed 1 m^3.
Containment Device:	See "Primary Containment Device" and "Secondary Containment Device".

Dilution:	Mixing of a liquid or solid (waste) with another liquid or solid for the primary purpose of reducing the concentration of the original liquid or solid (waste).
Environment:	All components of the earth including air, land, and water; all layers of the atmosphere, all organic and inorganic matter and living organisms, and interacting natural systems.
Filter Material:	All types of disposable filters from oil and gas production operations, including vehicle filters, oil pads, and absorbants used in maintenance of such operations.
Fixed Thermal Treatment Unit:	A thermal treatment unit which has been approved for operation at one geographical location only and which cannot be moved without a near complete dismantling.
Generator:	See Waste Generator.
Halogenated:	The production of incorporating a halgen (i.e. fluorine, chlorine, bromine, or iodine) into a chemical compound.
Incineration:	A thermal treatment process which destroys contaminants by oxidation in a controlled environment, at temperatures which are effective to reduce contaminants to ashes, inert gases, or vapours.
Inert Waste:	Any solid waste that, upon disposal to land, is not reasonably expected to undergo physical, chemical and/or biological changes to such as extent as to produce substances that may cause an adverse effect. Examples include demolition debris, concrete, asphalt, glass, cement returns, scrap metal, and dry timber or wood that has not been chemically treated. Also known as Non-reportable Waste.
Landfill:	A waste management facility at which waste is disposed by placing it on or in land in a manner that minimizes adverse human health and environmental effects, but does not include a land treatment facility, a surface impoundment, a salt cavern, or a disposal well. Oilfield landfills are a type of Oilfield Waste Management facility, and are approved by the EUB to accept only oilfield waste.
Land Treatment:	A planned and controlled mixing of the waste and surface soil in which the inherent soil processes are used to biodegrade, transform, and assimilate the waste constituents.
Leak Detection System:	A system designed for the early detection and collection of any leakage from a primary containment device.

Liquid:	A substance that contains free liquids as determined by the US EPA Method 9095 Paint Filter Liquids Test, *Test Methods for Evaulating Solid Wastes Physical/Chemical Methods* (EPA Publication No. SW 846).
Manifesting:	The use of documentation which must accompany shipments of dangerous oilfield waste on public roads to assist first responders in the event of an accident, and to confirm the proper shipment of wastes.
Mobile Thermal Treatment Unit:	A thermal treatment unit which can be moved in single or multiple units between geographical locations and which has received an approval to operate from Alberta Environmental Protection which does not pertain to a fixed geographical location.
Monitoring Well:	A well used to monitor the detection of liquid leakage from an underground primary or secondary containment device, or a well placed into a specific zone to enable the sampling of groundwater and to detect the presence of any leachate in the groundwater aquifer or the unsaturated zone.
Oilfield Waste:	An unwanted substance (by the generator) or mixture of substances that results from the construction, operation or reclamation of a well site, oil and gas battery, gas plant, compressor station, crude oil terminal, pipeline, gas gathering system, heavy oil site, oil sands site, or related facility.
Oily Waste:	A specific type of oilfield waste that contains oil or bitumen generated primarily during heavy oil production and typically consists of mainly sands and slop oil.
Operator Code:	The code assigned by the EUB to individual companies used to identify the licensee of wells or pipelines or the holder of approvals for batteries or other facilities.
Post-Closure Period:	The period of 25 years from final closure of a landfill, or so long as leachate that does not meet the performance standards for landfills (listed in Table 15.1) is generated at a landfill after final closure.
Primary Containment Device:	A device used to physically contain materials produced, generated, and used by the upstream petroleum industry.
Receiver:	See Waste Receiver.

Reclamation:	The removal of equipment or buildings or other structures or appurtenances, and/or the conducting of investigations to determine the presence of substances, and/or the decontamination of buildings, other structures, other appurtenances, land, or water, and/or the stabilization, contouring, maintenance, conditioning or reconstruction of the surface of land, and/or any other procedure, operation or requirement specified in the regulations.
Residuals:	The material left after a treatment process and may include ash, solids, water, and recovered contaminants.
Secondary Containment Device:	An impervious barrier placed between the primary containment device and the ground beneath and surround it, for the purpose of containing and preventing any leakage from the primary containment device from impacting the environment.
Sludge:	An accumulated free settling wet solid typically consisting of hydrocarbon, water, and inorganic sediments (i.e. sands, silts, etc.) where the BS & W exceeds 0.5 per cent
Small Quantity Exemption:	Oilfield wastes (other than those substances listed in Part B of Table 4 of the Schedule to the *Alberta Users Guide for Waste Managers* published by Alberta Environmental Protection), are not considered dangerous and are exempt from the storage requirements if they are produced at any single site in an amount less than 5 Kg per month, if a solid, or 5 L per month, if a liquid, and the total quantity accumulated does not exceed 5 Kg or 5 L at any time.
Solid:	A substance that does not contain free liquids and is not gaseous at standard conditions.
Stand-alone Facility:	A facility constructed and operated on its own site.
Storage:	The holding of materials produced, generated, and used by the upstream petroleum industry for a period of time until the products or wastes are used, transported, treated, or disposed.
Storage Area:	See Waste Storage Area.
Storage Facility:	See Waste Storage Facility.
Tank:	A device designed to contain materials produced, generated, and used by the upstream petroleum industry, which is constructed of impervious materials that provide structural support and may include such materials as concrete, plastic, fibreglass reinforced plastic, or steel.

Test Burn:	Operation of a thermal treatment process for the purpose of obtaining operational data, to determine if a process meets regulatory requirements. Test burns are required if the process has not previously received regulatory approvals for the waste tested.
Thermal Desorption:	A thermal treatment process which applies a heat source to a waste material to evaporate or volatilize contaminants from the waste material. Contaminant vapours are then incinerated in an oxidizing unit.
Thermal Distillation Recovery:	A thermal treatment process which applies a heat source to a waste material to evaporate or volatilize the contaminants. Contaminant vapours are then cooled, condensed, and collected. Collected liquids may then be separated into oil and water phases.
Thermal Oxidation:	See Incineration.
Thermal Phase Separation:	See Thermal Distillation Recovery.
Transfer Station:	See Waste Transfer Station.
Treatment:	Any method, technique, or process that is applied to change the physical, chemical, or biological character or composition of a substance.
Underground Storage Tank:	A tank that is partially or completely buried and does not allow for the visual inspection of the top, complete sides, and bottom of the tank without excavation.
Uppermost Formation:	A continuous water saturated geological stratum or strata including, but not limited to sand leases and acquifers, that is projected to be the most probable pathway or pathways for lateral transport of leachate.
Vaulted Storage Tank:	A tank that is contained in a concrete or other type of solid walled space (i.e. vault) either below or above ground level. The vault can be accessed through a manway or a top which is open to atmosphere. It may or may not be possible to visually inspect the tank on all sides.
Waste:	See Oilfield Waste.
Waste Generator:	The licensee and/or approval holder, or agent, as defined by the records of the Board, of a well or other facility, over which the Board has jurisdiction, which generates oilfield waste. Refer to Section 2.1, *Responsibilities*.

Waste Management Facility: (Oilfield)	A facility whose operation is approved by the EUB and consists of any or all of the following: waste processing facility, waste storage facility/waste transfer station, surface facility associated with disposal wells, biodegradation facility, oilfield landfill, thermal treatment facility, or any other oilfield waste management technology or facility.
Waste Receiver:	A person or party who accepts or receives oilfield waste for the purpose of storage, consolidation, transfer, treatment, or disposal. Refer to Section 2.1, *Responsibilities*.
Waste Storage Area: (Oilfield)	A storage area is part of an operating EUB approved oil and gas or oil sands facility. This is a designated area used to store oilfield waste in containers, tanks, bulk pads, or lined earthen excavations.
Waste Storage Facility: (Oilfield)	A stand-alone storage facility dedicated to the collection of one company's waste materials, until volumes are sufficient for an economic transfer of the wastes to treatment/disposal facilities.
Waste Tracking:	A system for monitoring and recording the generation, handling, treatement, and disposal of waste.
Waste Transfer Station:	A stand-alone storage facility that is used for the purpose of collecting upstream oilfield wastes, generated by various companies, until volumes are sufficient for an economic transfer of the wastes to treatement/disposal facilities.
Waste Transporter:	A person or party who receives or takes control of oilfield waste for the purpose of transportation.
Waste Treatment:	Any method, technique or process, including, without limitation, neutralization and stabilization, that is designed to change the physical, chemical, or biological character or composition of a substance.
Watercourse:	The bed and shore of a river, stream, lake, creek, lagoon, swamp, marsh, or other natural body of water, or a canal, ditch, reservoir, or other man-made surface feature whether it contains or conveys water continuously or intermittently.
Weather Protection:	A structure, protective coating or cover which ensures that the physical integrity of primary containment devices are not compromised by the elements of nature.
Wellhead Protection Zone:	The surface and subsurface area through which groundwater moves to reach a municipal or communal water supply well. The horizontal extent of the wellhead protection zone corresponds to the distance from the well to the boundary defined by a minimum draw-down, based on the normal pumping rate of 0.1 m from the equilibrium groundwater level.

Appendix 3.0

Recommended Test Methods

This section provides a listing of the recommended test methods for the analysis of water, soil, sludges, hydrocarbons and waste for characterization purposes.

Test methods not listed in this section may also be considered, providing they can be validated through collaborative studies, comparison to SRM (Standard Reference Materials), and statistical analyses (precision, standard deviation data).

The *Guidelines for Collaborative Study Procedure to Validate Characteristics of a Method of Analysis*, in the appendix of AOAC (1990), or *Method Development and Evaluation*, Method 1040 in APHA (1992), outlines steps that must be considered when preparing a collaborative study.

Analytical Methods; Reference Code Descriptions

1. AOAC, "Official Method of Analysis, of the Association of Official Analytical Chemists", current edition.

2. APHA-AWWA-WEF, "Standard Methods for the Examination of Water and Wastewater", current edition.

3. ASTM, "American Society for Testing and Materials", current edition.

4. Alberta Environmental Protection, "Methods Manual for Chemical Analysis of Water and Wastes", Alberta Environmental Centre, Vegreville, Alberta; October 1987, AECV87-M1, or latest edition.

5. Alberta Environmental Protection, "Methods Manual for Chemical Analysis of Pesticides and PCB Residues in Water and Wastes", Pollution Control Laboratory, Edmonton, Alberta, 1979.

6. Carter, M. R., "Soil Sampling and Methods of Analysis", Canadian Society of Soil Science, 1993.

7. Dionex Corporation Methods Manual.

8. ENVIRODAT, Dictionary of Codes, Environment Canada.

9. EPA, see US EPA.

10. FSPA, "Method Manual for Forest Soil and Plant Analysis", Kalra, Y. P. and Maynard, D. G., IR NOR-X-319, Forestry Canada.

11. McGill and Rowell, "Extraction of Oil from Soils", The Reclamation of Agricultural Soils after Oil Spills, Department of Soil Science, University of Alberta.

12. McKeague, J. A., "Manual on Soil Sampling and Methods of Analysis", Canadian Society of Soil Science, 1978.

13. NAQUADAT, Dictionary of Codes, Water Quality Branch, Environment Canada.

14. SM (Standard Methods), see APHA.

15. Syncrude, "Syncrude Analytical Methods for Oil Sand and Bitumen Processing", Syncrude Canada Ltd., Edmonton, Alberta, 1979.

16. TCLP, "Toxicity Characteristic Leaching Procedure".

17. TDGR, "Transportation of Dangerous Goods Regulation".

18. US EPA, "Test Methods for Evaluating Solid Waste; Physical/Chemical Methods, SW-846", 1986 or latest edition.

19. US EPA, "Environmental Protection Agency Regulations on Test Procedures for the Analysis of Pollutants", 40 CFR 136, 1984.

APPENDIX 3: RECOMMENDED TEST METHODS[1]			
ANALYTICAL PARAMETER/TEST	**SECTION WCR**	**CLASS**	**METHOD**
WASTE CHARACTERIZATION			
Liquids/Solids	-	-	US EPA method 9095 Paint Filter Liquids
Dispersible Form	Waste Control Regulation 1(f)	-	As described in the Regulation and Part 1 of Alberta Users Guide for Waste Managers
Flammable Liquids	Waste Control Regulation Schedule 1 Section 1(a)	3.1 3.2 3.3	ASTM D56-79, or ASTM D93-80, or ASTM D3828-81, or ASTM D3278-82
Flammable	Waste Control Solids Regulation Schedule 1 Section 1(a)	4	ASTM D93-80 US EPA METHOD 1010
Flammable Solids	Waste Control Regulation Schedule 1 Section 1(b)	4.1	Readily Combustible Burn Test or Burning Rate Test - Interim Compilation of Test Methods Under TDGR
Flammable Solids	Waste Control Regulation Schedule 1 Section 1(b) see also 14(2)(d)	4.2	Test for Pyrophoric Substances or Test for Self Heating Substances - Interim Compilation of Test Methods Under TDGR
Oxidizing Substances	Waste Control Regulation Schedule 1 Section 1(c)	5	Test for Solid Oxidizing Substances - Interim Compilation of Test Methods Under TDGR
Poisonous Solids or Liquids	Waste Control Regulation Schedule 1 Section 1(d)(i) and (ii)	6.1	By review of specified references or previous knowledge

[1]Refer to Alberta Users Guide for Waste Managers, March 1995, Alberta Environmental Protection

ANALYTICAL PARAMETER/TEST	SECTION WCR	CLASS	METHOD
Toxic Gases	Waste Control Regulation Schedule 1 Section 1(d)(iii)	2.3	By review of specified references or previous knowledge
Corrosive Solids or Liquids	Waste Control Regulation Schedule 1 Section 1(e)	8	Method 9040, 9041, 9045 SW-846 Test Methods for Evaluating Solid Waste, Physical/Chemical Methods - US EPA
Polychlorinated Biphenyls or, Articles containing PCB	Waste Control Regulation Schedule 1 Section 1(f)	9.1	US EPA Method 8080A or ASTM D 3304 or A Method for the Analysis of Polychlorinated Dibenzo-para-dioxins (PCDDs), and Polychlorinated Biphenyls (PCBs), etc. 1/RM/3, May 1990 Environment Canada
Toxic Leachate Waste - containing... Table 1	Waste Control Regulation Schedule 1 Section 1(g)(i)	9.2	Method 1311 Toxicity Characteristic Leaching Procedure (TCLP) US EPA Reg 40CFR261 App II
Toxic Leachate Waste - containing... Table 2	Waste Control Regulation Schedule 1 Section 1(g)(ii)	9.3	Method 1311 Toxicity Characteristic Leaching Procedure (TCLP) US EPA Reg 40CFR261 App II
Toxic Leachate Waste - containing Dioxin or Furan	Waste Control Regulation Schedule 1 Section 1(g)(iii)	9.3	A Method for the Analysis of Polychlorinated Dibenzo-para-dioxins (PCDDs), and Polychlorinated Biphenyls (PCBs), etc. 1/RM/3, May 1990 Environment Canada or Reference Method for the Analysis of Polychlorinated Dibenzo-para-dioxins (PCDDs), and Polychlorinated Dibenzo fruans (PCDFs) in Pulp and Paper Mill Effluents EPS 1/RM/19 Feb 1992 Environment Canada
Waste Type 200 Spent Filters produced in the fabric cleaning industry where an organic solvent is used as the cleaning agent	Table 3 of the Schedule to the Alberta User Guide for Waste Managers BUT see Section 3(h) of the WCR	9.3	Determine if the filters have been steam stripped in a steam cabinet with sparger for a period of 8 hours or more.
Waste Type 201 Spent Lubricating Oil and Undrained Lube Oil Filters Removed from Internal Combustion Engines	Table 3 of the Schedule to the Alberta User Guide for Waste Managers BUT see Section 3(h) of the WCR	9.3	Calculated DE for filters

ANALYTICAL PARAMETER/TEST	SECTION WCR	CLASS	METHOD
Landfillable halogenated solids	Waste Control Regulation Section 14(2)(a) Landfillable Hazardous Wastes	-	TCLP, General: - extract the sample in n-hexane using EPA 3550: - run the extract as per EPA 9076; or - ethyl acetate or n-hexane extraction followed by combustion and microcolormetric titration - Specific compounds - EPA 8240 and 8270 (SW-846)
Landfillable halogenated liquids	Waste Control Regulation Section 14(2)(b) Landfillable Hazardous Wastes	-	TCLP Petroleum Liquids: EPA 9076 for total halogenated organics, Alberta Environmental Protection M106.0 for PCBs Water: EPA 9020 for total halogenated organics, Alberta Environmental Protection A106.0 for PCBs PCB: analytical method involves the use of a gas chormatograph with an electron capture detector. The use of US EPA Method 8080A or ASTM D 3304 are recommended.
Landfillable nonhalogenated organic compounds	Waste Control Regulation Section 14(2)(c) Landfillable Hazardous Wastes	-	TCLP for cresols and cresylic acid: EPA 8270 following the acid extractables portions only, use EPA 3510 or 3550 for sample extraction as appropriate. For remainder of parameters (liquids and solids): EPA 8240 purge and trap GC/MS (3 additional purge parameters) or GC/FID.
Landfillable spontaneously combustible hazardous waste	Waste Control Regulation Section 14(2)(d) Landfillable Hazardous Wastes	4.2	Test for Pyrophoric Substances or Test for Self-Heating Substances - Interim Compilation of Test Methods Under TDGR
Landfillable liquid hazardous waste containing metals	Waste Control Regulation Section 14(2)(e) Landfillable Hazardous Wastes	-	arsenic SM* 3114B, beryllium SM* 3120B, cadmium Naquadat No. 48011, chromium hexavalent SM* 3500-CrD, lead Naquadat No. 8201, mercury SM* 3500 HgB, nickel Naquadat No. 28011, selenium SM* 3114B, silver SM*3500-AgC, thallium SM* 3500-TlC, uranium Dionex Method 48 Note SM*=Standard Method
Landfillable solid hazardous waste containing metals	Waste Control Regulation Section 14(2)(f) Landfillable Hazardous Wastes	9.3	Method 1311 Toxicity Characteristic Leaching Procedure (TCLP) US EPA Reg 4CFR261 App II (for hazardous waste buried with garbage) or (modified for hazardous waste buried alone, monofills)
Landfillable liquid hazardous waste containing cyanide	Waste Control Regulation Section 14(2)(g) Landfillable Hazardous Wastes (Liquid Cyanide)	-	Naquadat No. 06608L with auto colorimetric instrumentation

ANALYTICAL PARAMETER/TEST	SECTION WCR	CLASS	METHOD
Landfillable hazardous corrosive wastes	Waste Control Regulation Section 14(2)(h) Landfillable Hazardous Wastes	8	Method 9040, 9041, 9045 SW-846 Test Methods for Evaluating Solid Waste, Physical/Chemical Methods

APPENDIX 3: RECOMMENDED TEST METHODS

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
WATERS						
pH		10301	Combination Electrode/ pH meter			APHA 4500 H^+ (B); AOAC 973.41; EPA 9040
Specific Conductance		2041	Conductivity Meter	dS/m		APHA 2510 (B), AOAC 973.40; EPA 9050
Major Ions						
Calcium (Ca)	0.45 μm Filtration	20111 (D)	ICP -AES	mg/L	0.006	APHA 3500 Ca (C); APHA 3120 (B); EPA 6010
		20103 (D)	Atomic Absorption	mg/L	0.05	APHA 3500 Ca (B); EPA 7140
		02010 (D)	EDTA Titrimetric	mg/L	0.5	APHA 3500 Ca (D)
Magnesium (Mg)	0.45 μm Filtration	12111 (D)	ICP - AES	mg/L	0.002	APHA 3500 Mg (C) ; APHA 3120 (B); EPA 6010
		12102 (D)	Atomic Absorption	mg/L	0.01	APHA 3500 Mg (B); EPA 7450; AOAC 974.27
Potassium (K)	0.45 μm Filtration	19111 (D)	ICP - AES	mg/L	0.3	APHA 3500 K (C) ; APHA 3120 (B); EPA 6010
		19102 (D)	Atomic Absorption	mg/L	0.1	APHA 3500 K (B); EPA 7610; AOAC 973.53;
		19103 (D)	Flame Photometer	mg/L	0.02	APHA 3500 K (D)
Sodium (Na)	0.45 μm Filtration	11111 (D)	ICP - AES	mg/L	0.03	APHA 3500 Na (C) ; APHA 3120 (B); EPA 6010
		11102 (D)	Atomic Absorption	mg/L	0.1	APHA 3500 Na (B); EPA 7770; AOAC 973.54
		11103 (D)	Flame Photometer	mg/L	0.02	APHA 3500 Na (D)
Chloride (Cl)	0.45 μm Filtration	17203 (D)	Automated Ferricyanide Method (Colorimetric)	mg/L	0.1	APHA 4500 Cl (E); EPA 9250, 9251;
		17209 (D)	Ion Chromatography	mg/L	0.01	APHA 4500 Cl (F); APHA 4110 (B)
			Titrimetric	mg/L		APHA 4500 Cl (B)

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Nitrate (NO_3) (Nitrate + Nitrite - N) (Dissolved)	0.45 μm Filtration	7111/7112 (NO_3+NO_2)	Cadmium Reduction/ Automated	mg/L	0.002/	APHA 4500 NO_3 (E, F)
		7315 (NO_3)	Ion Chromatography	mg/L	0.01	APHA 4500 NO_3 (C); APHA 4110 (B)
		7120 (NO_3+NO_2)	Automated Colorimetric: Hydrazine Reduction	mg/L		APHA 4500 NO_3 (H)
Sulfate (SO_4) (Dissolved)	0.45 μm Filtration	16309	Ion Chromatography	mg/L	0.01	APHA 4500 SO_4 (B); APHA 4110 (B)
		16306	Automated Methylthymol Blue Method	mg/L	0.2	APHA 4500 SO_4 (F); EPA 9036
Metals, Total	Digestion: Nitric/hydrochloric EPA 3010, APHA 3030		ICP - AES	mg/L		APHA 3500 (C); APHA 3120 (B); EPA 6010
			Atomic Absorption	mg/L		APHA 3500 (B); APHA 3111 (B, C, D)
Mercury (Hg)	Digestion: Nitric/Sulphuric Acid and Persulfate/Permanganate:	1594	Cold-Vapour Atomic Absorption	mg/L	0.00005	APHA 3500 Hg (B); APHA 3112 (B); EPA 7470
Free Cyanides (CN)	Undigested, Distillation		Colorimetric			APHA 4500 CN (E)
Oil and Grease[2]	Separatory funnel extraction with freon (APHA 5520 (D))	6524	Infrared Analysis	mg/L		APHA 5520 (C)
	Separatory funnel extraction with n-hexane or MTBE or Freon	6521	Gravimetric Analysis	mg/L	1	APHA 5520 (B)
Total Petroleum Hydrocarbon (Mineral Oil and Grease)	Separatory funnel extraction with freon: Silica gel clean up (APHA 5520 (F))	6579	Infrared Analysis	mg/L	0.2	APHA 5520 (C)
			Gravimetric Analysis	mg/L		APHA 5520 (B)

[2]Due to restrictions on the use and manufacture of freon, new methods are currently being developed for the analysis of Oil and Grease.

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Total Organic Carbon (TOC)		6001	Combustion-Infrared Carbon Analyzer	mg/L	0.5	APHA 5310 (B); AOAC 973.47
		6005			0.1	
Phenols	Steam distillation		Direct Photometric Method: with 4-AAP	mg/L		APHA 5530 (D)
		6537	Automated Photometric Method: with 4-AAP	mg/L	0.001	EPA 420.2
Total Dissolved Solids (TDS)	Filter thru glass fibre filter (Watman 934 A/H) or equiv.		Total Dissolved Solids Dried at 180 °C	mg/L		APHA 2540 (C)
		8, 10	Calculated (Ca+Mg+Na+K+Cl+ SO_4+NO_3+(0.6 x Alkalinity))	mg/L		APHA 1030 (F)
Chemical Oxygen Demand (COD)	$K_2Cr_2O_7/H_2SO_4$ Digestion	8304	Closed Reflux/Colorimetric	mg/L	5	APHA 5220 (D)
		8301	Closed Reflux/Titrimetric	mg/L	1	APHA 5220 (C);

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
SOILS AND SLUDGES						
Saturated Paste and Paste Extract						McKeague 3.21
Water Saturation (%)	Saturated Paste		Gravimetric: (Water content/Weight basis)	%		McKeague 3.21; McKeague 2.411; Carter 18.2.2
Texture			Hand Method			McKeague 4.8
Hydraulic Conductivity	Saturated Soil Sample		Constant-Head Core Method			McKeague 2.51; Carter 55.2; EPA 9100
			Falling-Head Core Method			Carter 55.3, EPA 9100
pH	Saturated Paste Extract 1:2 Soil in 0.01 M $CaCl_2$	10317	pH Meter			McKeague 3.11, Carter 16.3; EPA 9045;
	Saturated Paste Extract 1:2 Soil : Water	10316	pH Meter			McKeague 3.14, Carter 16.2; EPA 9045;
Electrical Conductivity (EC)	Saturated Paste Extract	2041	Conductivity Meter	dS/m		APHA 2510 (B); EPA 9050; Carter 18.3.1; McKeague 4.1
Major Ions:						
Calcium (Ca)	Saturated Paste Extract 0.45 μm Filtration	20111	ICP - AES	mg/L		APHA 3500 Ca (C); APHA 3120 (B); EPA 6010
		20103	Atomic Absorbtion	mg/L		APHA 3500 Ca (B); EPA 7140
			EDTA Titrimetric	mg/L		APHA 3500 Ca (D)
Magnesium (Mg)	Saturated Paste Extract 0.45 μm Filtration	12111	ICP - AES	mg/L		APHA 3500 Mg (C); APHA 3120 (B); EPA 6010
		12102	Atomic Absorbtion	mg/L		APHA 3500 Mg (B); AOAC 974.27; EPA 7450
Potassium (K)	Saturated Paste Extract 0.45 μm Filtration	19111	ICP - AES	mg/L		APHA 3500 K (C); APHA 3120 (B); EPA 6010
		19102	Atomic Absorbtion	mg/L		APHA 3500 K (B); AOAC 973 53; EPA 7610
		19103	Flame Photometer	mg/L		APHA 3500 K (D)

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Sodium (Na)	Saturated Paste Extract 0.45 μm Filtration	11111	ICP - AES	mg/L		APHA 3500 Na (C); APHA 3120 (B); EPA 6010
		11102	Atomic Absorbtion	mg/L		APHA 3500 Na (B); AOAC 973.54; EPA 7770
		11103	Flame Photometer	mg/L		APHA 3500 Na (D)
Chloride (Cl)	Saturated Paste Extract 0.45 μm Filtration	17203	Automated Ferricyanide Method (Colorimetric)	mg/L		APHA 4500 Cl (E); EPA 9250, 9251
		17209	Ion Chromatography	mg/L		APHA 4500 Cl (F); APHA 4110 (B)
			Titrimetric	mg/L		APHA 4500 Cl (B)
Nitrate (NO_3) (NO_3+NO_2)	Saturated Paste Extract 0.45 μm Filtration	7111 /7112 (NO_3+NO_2)	Cadmium Reduction/ Automated Cd Reduction	mg/L		APHA 4500 NO_3 (E, F)
		7315 (NO_3)	Ion Chromatography	mg/L		APHA 4500 NO_3 (C); APHA 4110 (B)
		7120 (NO_3+NO_2)	Automated Colorimetric: Hydrazine Reduction	mg/L		APHA 4500 NO_3 (H)
Sulfate (SO_4)	Saturated Paste Extract 0.45 μm Filtration	16309	Ion Chromatography	mg/L		APHA 4500 SO_4 (B); APHA 4110 (B)
		16306	Automated Methylthymol Blue Method	mg/L		APHA 4500 SO_4 (F); EPA 9036
Water and Solids Content			Gravimetric Analysis: Oven Dry			McKeague 2.411; Carter 51.2
Available Nutrients:						
Ammonia Nitrogen (NH_3-N)	Extraction 2 N KCl (Carter 4.4)	07505 (D)	Phenate Method; Automated Phenate Method	mg/L		APHA 4500 NH_3 (D, H); Carter 4.4
		310	Ammonia Selective Electrode	mg/L		APHA 4500 NH_3 (F, G);
Nitrate Nitrogen (NO_3-N + NO_2-N)	Extraction 2 N KCl (Carter 4.3)	7111 /7112 (NO_3+NO_2)	Colorimetric Method (Cadmium Reduction)	mg/kg		APHA 4500 NO_3 (E, F), McKeague 4.311; Carter 4.3
		7315 (D)	Ion Chromatography	mg/L		APHA 4500 NO_3 (C)

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Phosphorous, extractable (Ortho phosphate)	Medium Strength "Bray" Extract	15255 (D)	Automated Ascorbic Acid; Photometric	mg/L		APHA 4500 P (F); AOAC 973.55, 973.56
		15317 (E)	Colorimetric/Autoanalyzer			McKeague 4.43, McKeague 4.44, FSPA 13.1
Nitrogen, Total (sum of ammonia, nitrate and nitrite nitrogen.)	Micro-Kjeldahl Digestion APHA 4500 N_{ORG}	7015	Phenate Method/Automated	mg/L		APHA 4500 NH_3 (D,H); Carter 22.2
		7012	Ion Selective Electrode	mg/L		APHA 4500 NH_3 (F, G)
Phosphorous, Total	Sodium Carbonate Fusion (Carter 23.2.2)	15255	Automated Ascorbic Acid; Photometric	mg/L		APHA 4500 P (F); AOAC 973.55, 973.56
Cation Exchange Capacity (CEC)			Ammonium Acetate Saturation			McKeague 3.321; Carter 19.4
			Sodium Acetate Saturation			McKeague 3.34
Sodium Adsorption Ratio (SAR)	Saturated Paste Extract		Calculated From Soluble Ions (Ca, Mg, and Na)			McKeague 3.26; Carter 18.4.3
Metals, Total	Digestion: Nitric Acid/H_2O_2 (open beaker) EPA 3050) or, Nitric Acid (closed vessel Microwave) EPA 3051		ICP - AES	mg/kg		APHA 3500 (C); APHA 3120 (B); EPA 6010
			Atomic Absorption	mg/kg		APHA 3500 (B); APHA 3111 (B, C, D)
Boron (B)	Hot Water Extraction	382 (E)	ICP - AES	mg/kg		APHA 4500 B (D); APHA 3120 (B); EPA 6010; Carter 12.2.4
		5106 (D)	Azomethine-H Method	mg/kg		McKeague 4.61; Carter 12.2.2
		5102 (D)	Curcumin Method	mg/kg		APHA 4500 B (B); McKeague 4.62;
Mercury (Hg)	Digestion: Nitric Acid (closed vessel microwave) EPA 3051	80051 (T)	Cold Vapour Atomic Absorption	mg/kg		APHA 3500 Hg (B); APHA 3112 (B); EPA 7471;
	Digestion: Acid/$KMnO_4$					

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Arsenic (As)	Digestion: Nitric/Sulphuric Acid	33011 (T)	Continuous Hydride Generation - Atomic Absorption	mg/L		APHA 3500 As (B); APHA 3114 (C), EPA 7061
	Digestion: Nitric Acid/H_2O_2 (EPA 3050) or, Nitric Acid (EPA 3051)	33009	Atomic Absorption Furnace Technique	mg/L		APHA 3500 As (B); APHA 3113 (B); EPA 7060
			ICP-AES			APHA 3500 As (D); APHA 3120 (B); EPA 6010
Selenium (Se)	Digestion: Nitric/Sulphuric Acid	34011	Continuous Hydride Generation - Atomic Absorption	mg/L		APHA 3500 Se (C); APHA 3114 (C), EPA 7741
	Digestion: Nitric Acid/H_2O_2 (EPA 3050) or, Nitric Acid (EPA 3051)	34009	Atomic Absorption Furnace Technique	mg/kg		APHA 3500 Se (H); APHA 3113 (B); EPA 7740
			ICP-AES			APHA 3500 Se (I); APHA 3120; EPA 6010
Oil and Grease[3]	Separatory funnel extraction with freon (APHA 5520 (D))		Infrared Analysis	mg/kg		APHA 5520 (C)
	Separatory funnel Extraction with n-hexane or MTBE or Freon		Gravimetric Analysis	mg/kg		APHA 5520 (B)
Total Petroleum Hydrocarbon (Mineral Oil and Grease)[3]	Separatory funnel extraction with freon: Silica Gel Clean up (APHA 5520 (F))		Infrared Analysis	mg/kg		APHA 5520 (C)
			Gravimetric Analysis	mg/kg		APHA 5520 (B)
% Oil	Soxhlet Extraction with Methylene Chloride		Gravimetric Analysis	%	0.01	EPA 3540; McGill and Rowell
Total Organic Carbon /Organic Matter	Wet Oxidation		Titration	mg/L		McKeague 3.613; Carter 21.2
	Wet Combustion		Titration	%		McKeague 4.22

[3]Due to restrictions on the use and manufacture of freon, new methods are currently being developed for the analysis of Oil and Grease.

ANALYTICAL PARAMETER/TEST	METHOD PREPARATION	ENVIRODAT CODE	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Phenols	Extraction: NaOH		Direct Photometric Method: with 4-AAP	mg/L		APHA 5530 (D)
		6537	Automated Photometric Method: with 4-AAP	mg/L	0.001	EPA 420.2
Bulk Density			Core Method: Mineral Soils	g/L		McKeague 2.2

ANALYTICAL PARAMETER/TEST	MATRIX	METHOD PREPARATION	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
HYDROCARBON FRACTIONATION						
Flash Point	Liquid/Soil and Sludge		Closed Cup Pensky-Martens	°C		ASTM D-93-77, EPA 1010
Spontaneous Combustion	Liquid/Soil and Sludge		Hot Circulating Oven @ 140°C (initial temp)			Transportation of Dangerous Goods Regulation 3.4.3.5 Division 4.2
Screening Tests:						
Light Aliphatic Compounds: (Total Purgeable Hydrocarbons) (C_3 - C_{14})	Liquid	Purge and Trap (EPA 5030)	GC/MS, GC/FID, GC/PID			EPA 8015; EPA 8240
		Headspace (EPA 3810)				
	Soil/Sludge	Extraction: Methylene Chloride (EPA 5030)				
Total Extractable Hydrocarbons (TEH) (C_8 - C_{30}) (C_8 - C_{60}) Also referred to as Total Petroleum Hydrocarbons (TPH) if cleanup is employed	Liquid	Extraction: Methylene Chloride, Carbon disulphide, or acetone (EPA 3510, 3520), Cleanup: (EPA 3610)	GC/MS, GC/FID, GC/PID			EPA 8000, EPA 8270
	Soil/Sludge	Soxhlet Extraction: Methylene Chloride (EPA 3540)				
Oil and Grease[4] (C_{10}+)	Liquid	Extraction: n-hexane, MTBE or Freon (APHA 5520 (D)).	Infrared Analysis	mg/L, mg/Kg		APHA 5520 (C)
	Soil and Sludge	Soxhlet Extraction: Methylene Chloride (EPA 3540)	Gravimetric Analysis	mg/L, mg/Kg		APHA 5520 (B)

[4]Due to restrictions on the use and manufacture of freon, new methods are currently being developed for the analysis of Oil and Grease.

ANALYTICAL PARAMETER/TEST	MATRIX	METHOD PREPARATION	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Mineral Oil and Grease[5] ($C_{10}+$) Also referred to as Total Petroleum Hydrocarbons (TPH) if analyzed by I.R..	Liquid/Soil and Sludge	Extraction: Freon: Silica Gel Cleanup (APHA 5520 (F))	Infrared Analysis	mg/L, mg/Kg		APHA 5520 (C)
			Gravimetric Analysis	mg/L, mg/Kg		APHA 5520 (B)
Specific Tests:						
Volatile Organic Compounds (VOC)	Liquid	Purge and Trap (EPA 5030)	GC/MS			EPA 8015; EPA 8240
		Headspace (EPA 3810)				
	Soil/Sludge	Extraction: Methanol (EPA 5030)				
Monocyclic Aromatics (BTEX: C_6 - C_9)	Liquid	Purge and Trap (EPA 5030)	GC/PID			EPA 8020
		Headspace (EPA 3810)				
	Soil/Sludge	Extraction: Methanol (EPA 5030)				
Poly and Hetro-cyclic Aromatics (PAH)	Liquid	Extraction: Methylene Chloride (EPA 3510) Cleanup: EPA 3611, 3630, 3640	GC/FID			EPA 8100
	Soil/Sludge	Soxhlet Extraction: Methylene Chloride (EPA 3540) Cleanup: EPA 3611, 3630, 3640	GC/MS: Capillary Column Technique			EPA 8270
			HPLC			EPA 8310
Asphaltenes	Liquid/Soil and Sludge	Extraction: Benzene/n-pentane	Gravimetric (Weight Basis)			Syncrude Method 5.1

[5]Due to restrictions on the use and manufacture of freon, new methods are currently being developed for the analysis of Oil and Grease.

ANALYTICAL PARAMETER/TEST	MATRIX	METHOD PREPARATION	INSTRUMENTATION METHOD	UNITS	DETECT. LIMIT	METHOD REFERENCE
Polychlorinated Biphenols (PCB)	Liquid	Extraction: Methylene Chloride (EPA 3510, 3520) Cleanup (3620, 3650, 3660)	GC/Electron Capture Detection			EPA 8000; EPA 8080
	Soil/Sludge	Extraction: Acetone/Hexane (EPA 3540, 3550) Cleanup (3620, 3640, 3660)				
Halogenated Organics						
Adsorbable Organic Halides (AOX)	Liquid	Acidified (Nitric acid); Passed through column of GAC, Washed, Combusted	Neutron Activation			EPA 9022, Helmke 1982
Extractable Organic Halides (EOX)	Soil/Sludge	Extraction: Ethyl Acetate, Combusted	Microcoulometric-Titration Detector			EPA 9020
Total Organic Halides (TOX)	Liquid	Extraction: Cyclohexane-MTBE, Washed, Combusted (Liquids can also be passed through GAC and then combusted)				
	Soil/Sludge					
Solvent Scan (including): Acetone, benzene, n-butyl alcohol, carbon disulphide, cresols and cresylic acid, cyclohexanone, ethyl acetate, ethyl benzene, ethyl ether, isobutanol, methanol, methyl ethyl ketone, nitrobenzene, 2-nitropropane, pyridine, toluene, xylene	Liquid	Direct Headspace (EPA 3810)	GC/MS			EPA 8240
	Soil/Sludge	Extraction: Methanol/Water Followed by Direct Headspace (EPA 3810)				

Appendix 4.0

Requirements for Site Assessment and Groundwater Protection

4.1 Introduction

The **purpose** of this appendix is to identify the minimum requirements for a site assessment and a groundwater monitoring program.

It is the operator's responsibility to:

- determine if additional work beyond the minimum is required, and
- to justify why the actions taken at a specific site are sufficient. Site assessments and groundwater monitoring systems will be audited by EUB staff.

In the interest of protecting the environment, the EUB requires certain facilities under its jurisdiction (i.e. oilfield waste management facilities) to have a monitoring system that will provide an early indication of potential groundwater impact.

To properly design and implement an appropriate monitoring system, operators will be required to first conduct a site assessment. However, if upon completion of the site assessment it is concluded that groundwater monitoring will not provide sufficiently early detection of contamination, alternative monitoring systems shall be implemented such as soil vapour surveys, soil sampling surveys, or shallow geophysical techniques (i.e. electrical conductivity, electromagnetic, or ground penetrating radar surveys).

Qualified expertise must be employed to:

- evaluate hydrogeological and geological information,
- conduct a site investigation and establish the hydrogeologic conditions for the site,
- implement an appropriate monitoring system, and
- interpret analytical results.

The design of a monitoring program should be based upon the information obtained from the site assessment, and it should take into account the type of activity that has occurred or could occur on that site.

4.2 Site Assessment

Site assessments must be conducted at a sufficient level of detail to allow for the implementation of an appropriate monitoring program.

Published reports, maps, aerial photographs, existing water well data, research papers, or any other information available in the public domain should be used to establish the regional hydrogeologic setting within a 3 km radius of the facility site. The site geology and hydrogeology should then be determined from on-site investigations.

The following outlines the minimum information that should be compiled and evaluated as part of a site assessment. The information that must be submitted to the EUB is outlined in the monitoring and reporting section.

1. Regional Assessment

A. Setting

A description of the regional setting including the following:

(a) a detailed scale topography map that includes all local surface water bodies,

(b) soil types and distribution, and

(c) any nearby industrial facilities, waste transfer stations, landfills, etc. that may affect quality or flow of groundwater.

B. Geology and Hydrogeology

A description of the geology (surficial deposits and underlying bedrock) and hydrogeology of the area based on the following, if available:

(a) surficial geology maps,

(b) bedrock topography/geology maps,

(c) hydrogeologic maps and cross sections,

(d) published reports, and

(e) air photos.

C. Groundwater Use in the Area

Based on available information from government records (i.e. Groundwater Information Centre of the Hydrogeology Branch of Alberta Environmental Protection):

(a) identify all surface and groundwater users within a 3 km radius of the facility, and

(b) identify depths, specific yields, and water quality of aquifers.

2. Site Investigation

The objective of the site investigation is to reconcile the information gathered during the regional assessment with the true site specific conditions.

Based on the regional assessment, the operator should have a preliminary understanding of the soil characteristics, geology, and groundwater chemistry and flow directions. These conditions along with knowledge of the type of activity that either has taken place or will take place on the site, should be used to determine the placement of the groundwater monitoring wells.

As the site assessment will be used to establish a baseline for further monitoring and reporting, it is important that the initial site investigation includes a wide spectrum of parameters and constituents. This assessment then becomes the baseline for all future monitoring and reporting. From this broad list of parameters, the operator can then choose a smaller list of "critical" parameters to monitor over the longer term. As a minimum, the groundwater must be tested for the following parameters:

- pH,
- major ions,
- electrical conductivity,
- total metals, and
- mineral oil and grease.

Refer to Section 4.3, *System Design,* for information on well placement and the construction and installation of monitoring wells.

3. Site Specific Data

On-site investigations during the drilling and installation stages of the monitoring wells should provide the following site specific information:

(a) surface and near surface features, such as natural slope of the site, existing or potential sources of contamination and any manmade or natural features that may act as conduits for contaminant migration, including:

(i) site topography, locations of all surface water, and surface drainage patterns,

(ii) on-surface or buried pipelines, utility lines, conduits, pits, or tanks,

(iii) buildings, loading facilities, or storage areas,

(iv) disposal or source wells,

(v) existing or abandoned monitoring wells or standpipes,

(vi) areas containing buried fill material or waste, and

(vii) areas of known extensive or frequent spills,

(b) a description of the soil characteristics including:

(i) the geological parent materials, thickness, and type and depth of genetic horizons,

(ii) physical characteristics including texture, evidence of fracturing, internal drainage characteristics, and an estimate of moisture content, and

(iii) background chemical characteristics including pH, electrical conductivity, major extractable ions, cation exchange capacity, total metals, percent oil, and sodium adsorption ratio,

(c) a description of the hydrogeology including:

(i) type, thickness, and distribution of each stratigraphic unit,

(ii) depth of water table,

(iii) estimate of the moisture content and its variation in the unsaturated zone,

(iv) measured hydraulic conductivity of the first saturated strata,

(v) horizontal and vertical direction, rate, and approximate velocity of groundwater movement, and

(vi) local groundwater discharge and recharge areas, and

(d) a description of the groundwater quality from the initial sampling of the monitoring wells including, as a minimum, the following:

(i) pH,

(ii) major ions,

(iii) conductivity,

(iv) total metals, and

(v) mineral oil and grease.

4. Site Assessment Results

After the completion of the site assessment, the operator should be able to:

(a) determine potential pathways of contaminant migration,

(b) identify the depth, location, and type of any contaminant encountered, the probable source, and the appropriate remedial actions to be undertaken,

(c) assess whether monitoring the unsaturated zone alone or in concert with the groundwater, or whether any other monitoring techniques, are warranted, and

(d) assess whether additional groundwater monitoring wells are required.

4.3 System Design

1. Strategy of Well Placement

Prior to the installation of monitoring wells, the site topography and local drainage features can often provide an indication of the groundwater flow directions. Techniques such as electromagnetic surveys, ground penetrating radar, and drive-point wells, may be utilized to assist in the placement of the permanent monitoring system. The following identifies the minimum requirements for a groundwater monitoring system.

(a) A minimum of four permanent monitoring wells must be installed during the initial stage of a groundwater monitoring program.

(b) Three shallow wells shall be installed to determine the depth and horizontal direction of groundwater flow in the shallowest water bearing zone, typically the permanent water table.

(c) If a perched water table exists, additional wells will be required to monitor this situation.

(d) Of the three shallow wells monitoring the permanent water table, one must be placed hydraulically upgradient of the site and two downgradient. This upgradient well should be situated to provide the best indication of background (unimpacted) groundwater chemistry at the site.

(e) A fourth monitoring well shall be installed beside the downgradient well most likely to be impacted, and completed to allow the measurement of the vertical hydraulic gradient.

If groundwater contamination is detected, subsequent monitoring wells may be required to delineate the vertical and horizontal extent of contamination. Care must be taken during the drilling and completion of all wells to ensure that they do not serve as conduits for migration of contaminants.

2. Monitoring Well Construction and Installation

A variety of drilling methods are available for the installation of monitoring wells. The choice of method will often be dictated by the site conditions.

Recognized industry practices must be followed to ensure that:

- contaminants are not introduced into the well during construction,
- a minimum disturbance of subsurface materials occurs,
- a representative sample can be collected, and that
- no contaminants from zones other than the interval at which the well is screened will be able to enter the well.

Information on appropriate monitoring well design, installation, completion, development, and sampling procedures can be found in the references relating to site assessment and groundwater protection, listed in Appendix 1.0, *References*. The EUB expects operators, or their consultants, to implement monitoring systems in accordance with industry standards.

Monitoring wells that are no longer used as part of the monitoring program (i.e. as a result of damage or inappropriate placement) must be properly abandoned. Operators must document their abandonment procedures and make them available to EUB staff upon request.

4.4 Monitoring and Reporting

1. Initial Information Submission

A concise summary outlining the information obtained from the site assessment and the monitoring program implemented at the site must be submitted to the EUB. This summary must include:

(a) a facility plot plan at an appropriate scale that clearly identifies any features listed in item 2.2.1a), as well as the locations of the groundwater monitoring wells and the horizontal direction of the shallow groundwater flow,

(b) the location of all surface waters and inferred areas of groundwater discharge within a 3 km radius of the facility,

(c) a summary of local groundwater and surface water users within a 3 km radius of the facility,

(d) a summary of the regional hydrogeology and geology for the area in which the site is located, as derived from existing data in the public domain,

(e) monitoring well construction, completion, and monitoring details including:

- (i) the rationale for the location, depth, and screened interval,
- (ii) a description of the construction materials and completion details,
- (iii) methods employed to develop the wells,
- (iv) sampling and testing procedures, and
- (v) the ground level elevation, casing top elevation, depth to water, total depth of well, and screened interval for each well, presented in tabular form,

(f) site specific information, determined during the drilling and installation of the monitoring wells, including the following:

- (i) the physical characteristics of the soil including thickness, texture, internal drainage characteristics, evidence of fracturing, and an estimate of the moisture content,

(ii) background chemical characteristics of the soil including pH, electrical conductivity, major extractable ions, cation exchange capacity, total metals, per cent oil, and sodium adsorption ratio,

(iii) the description of the surficial geology, including the type and thickness of the strata,

(iv) the depth of the shallowest water bearing strata (depth of the water table) and the hydraulic conductivity of this zone, including raw test data and method of analysis,

(v) the horizontal and vertical directions, rates and approximate velocities of the groundwater flow,

(vi) a description of the quality of the groundwater including, as a minimum, the initial results obtained for pH, electrical conductivity, major ions, total metals, and mineral oil and grease, and

(vii) the depth, location, and type of any contaminant encountered, the probable source of the contaminant, and a discussion of the remedial actions to be undertaken, and.

(g) a discussion of whether any other monitoring techniques are warranted and whether any other monitoring wells are required.

2. Routine (Annual) Monitoring and Reporting

Each groundwater monitoring system, once established, shall be sampled twice per year, spring and fall. More extensive monitoring may be required in some instances depending on the specific site and facility. The monitoring results must then be compiled into an annual report. It is the responsibility of the operator of the facility to ensure that the sampling is undertaken and the annual report is prepared.

Annual reports must be prepared for each facility with a groundwater monitoring system and must be:

- prepared by 31 March of each year,
- retained on-site for a period of 5 years, and
- made available to EUB personnel upon request.

The annual report must concisely detail the present monitoring results as well as those from the previous 5 years.

The annual report shall contain the following:

(a) a site map showing the locations of facility features and monitoring wells, as well as the horizontal direction of the shallow groundwater flow,

(b) a tabular compilation of the present and previous 5 years monitoring results including groundwater elevation and analyses for each monitoring well,

(c) a tabular compilation of the present and previous 5 years results from any other monitoring technique employed (the map in item (a) above must be modified to reflect this monitoring technique),

(d) a summary of any work undertaken to augment the monitoring system,

(e) an assessment of whether the monitoring results indicate potential groundwater impact,

(f) a discussion of any work undertaken to alleviate potential impacts identified in item (e) above or of the status of any on-going work undertaken to alleviate previously identified impacts, and

(g) a trend analysis of the monitoring data to predict the potential for future groundwater impairment.

If it is determined that the groundwater at the site has been impacted, the EUB must be notified of this within 60 days of the sampling date.

Groundwater impact determination should utilize the trending analysis described above along with other statistical methods. For naturally occurring constituents, any significant deviations above normally expected seasonal fluctuations would be considered important. The basis for this assessment would be the background levels established from the initial site assessment. The presence of constituents not normally found in groundwater, such as BTEX or phenols, must be reported. This discussion must include a description of the impact, including the source of the impact, any potential for off-site contamination, and a preliminary proposal to address the problem.

It is expected that good practice will be applied in sampling and analysis. For examples of methods of analysis, refer to Appendix 3.0, *Recommended Test Methods,* and the references relating to site assessment and groundwater protection listed in Appendix 1.0 *References*.

Appendix 5.0

Calculation of the Reynold's Number

The Reynolds Number (Re) can be determined as follows:

$$Re = \frac{VD}{Ki}$$

where V = average velocity in the secondary chamber used to calculate residence time, m/s

D = diameter (or equivalent diameter) or flow stream in the secondary chamber used to calculate residence time, m

Ki = kinematic viscosity, m^2/s

As an example of this calculation, assume a secondary chamber has a wet gas flowrate of 0.2 Nm^3/s; a square internal duct size of 0.61 x 0.61 m; and an equivalent diameter of 0.67 m and is 1 m long. The gas flow is at a temperature of 1 000°C, and is at a velocity of 2.3 m/s. From Figure 1; $K=140 \times 10^{-6}$ at 1 000°C.

Therefore:

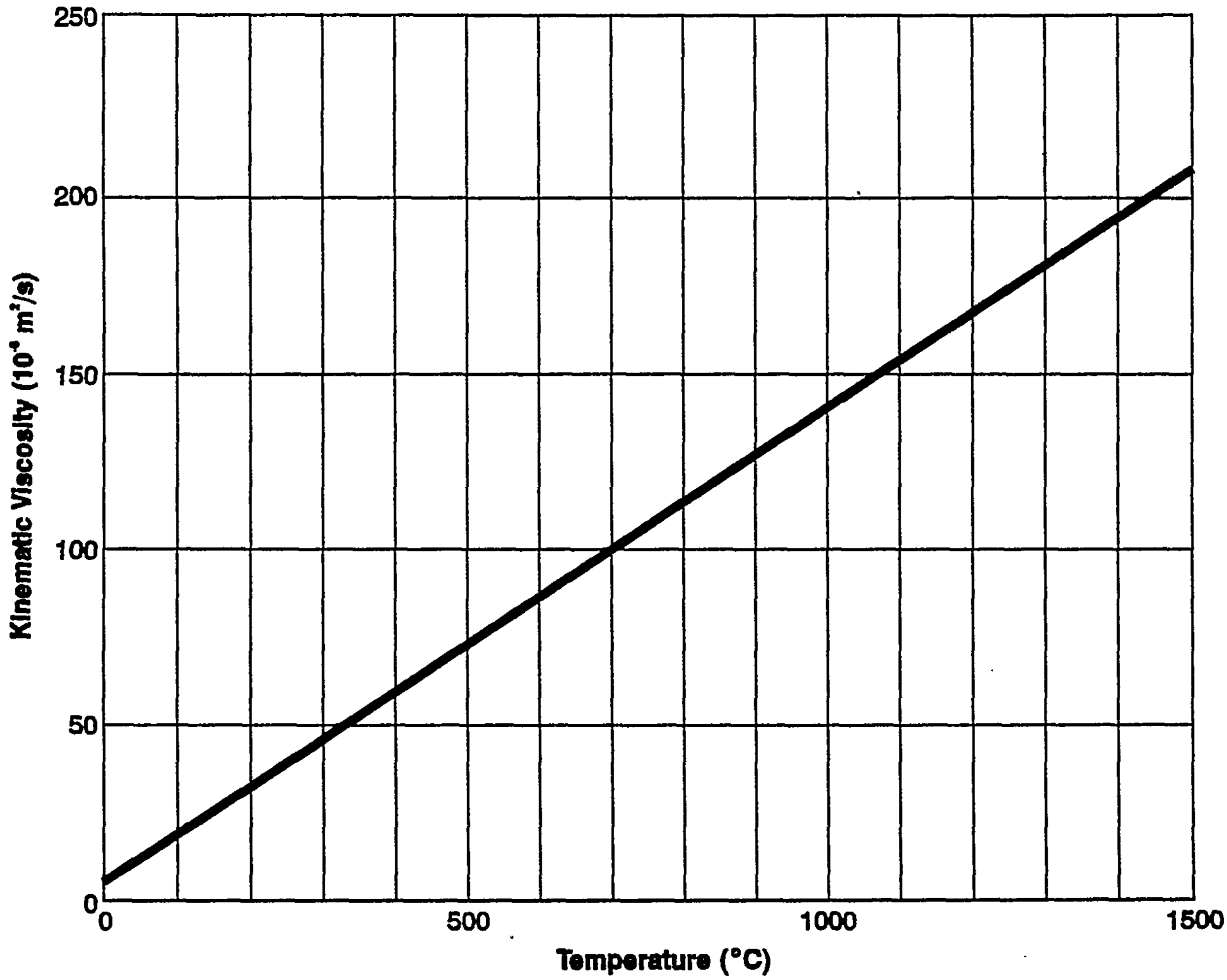
$$Re = \frac{VD}{Ki}$$

$$Re = \frac{2.3 \ m/s \times 0.67 m}{140 \times 10^{-6} m^2/S}$$

$$= 11\ 000$$

This is greater than the minimum Re of 10 000 and turbulence can be assumed to be adequate.

Figure 1 Air Viscosity Versus Temperature



Appendix 6.0

Waste Minimization

6.1 Introduction

The **purpose** of this section is to describe waste minimzation philosophies and to promote an active participation in waste minimization by all licensees and/or approval holders.

Waste minimization is a continuous improvement practice. It is an ongoing process involving the 4Rs (Reduce, Reuse, Recycle, and Recover), and includes the full-cycle assessment of environmental effects and the associated economic and technical feasibility of the various management options.

The oil and gas industry is encouraged to promote waste minimization within their operations. Because of the potentially significant volumes of waste which require handling and disposal, the industry should ensure effective management strategies are employed to minimize and effectively handle wastes in a diligent manner.

The 4Rs represent the minimization strategies that may be employed to reduce wastes requiring disposal.

Reduction offers petroleum companies the greatest options for waste minimization and can usually be applied on-site. The ultimate way to manage waste is to not produce it in the first place, or to only produce environmentally non-reportable wastes which are easier and less costly to dispose. Reuse can also be applied on-site. The on-site application of Recycle and Recover are limited and usually require the use of an off-site waste contractor for waste treatment.

The most effective waste management practice is to avoid the production of waste in the first place.

Waste minimization provides:

- savings in raw material and production costs,
- a reduction in environmental implications (risk),
- savings in time and energy,
- lower waste treatment and disposal costs,
- reduced liabilities,
- improved corporate image, and
- less employee exposure to hazardous materials.

6.2 Waste Minimization Strategies

1. Reduce

Waste reduction is the preferable option. It is best to produce as little waste as possible by reducing the waste at source. In some cases, the production of the waste can be totally eliminated. For example:

- Purchase chemicals in bulk to reduce container waste and the frequency of possible spillage when handling.
- Segregate process streams to minimize sludge or liquid production, and to optimize reduction/recycle options.
- Prevent leaks and spills to eliminate contaminated soils.
- Dry sludges prior to treatment and disposal, thereby reducing the waste volume and allowing easier dry waste disposal.
- Train and motivate employees to practice waste reduction.
- Improve material receiving, storage, and handling practices to reduce losses.
- Install more efficient processing equipment or improve the operating efficiency of existing equipment.
- Analyze compressor and engine lubricating oils by a laboratory to determine if an oil change is actually required.
- Reduce the use of filters in water injection streams, if possible.
- Discontinue the use of treater hay from treater vessels.
- Review the need for certain products in operations.
- Use less hazardous substitutes for toxic products (i.e. the use of fresh water gel drilling systems as opposed to invert muds, when possible).

2. Reuse

If a waste is produced, every effort should be made to reuse it, for example:

- clean oil rags,
- use reusable filters,
- reuse filtered lube oil for chemical injection pumps, and

- filter gear lubricating oil to extend period of use.

3. Recycle

This option usually requires off-site contract services.

Although recylcing does help to conserve resources and reduce wastes, there are economic and environmental costs associated with waste collection and recycling processes. Recycling should only be used for wastes which cannot be reduced or reused. Segregate all wastes that are to be recycled. Recycling examples include:

- Use waste acids for the neutralization of caustic wastes.
- Recycling lube oil, glycol, solvents, unspent chemicals, batteries, paper, metal, plastic containers, and glass.

4. Recover

This option usually requies off-site contract services.

Some wastes may contain recoverable substances that can be reused, for example:

- Separating and recovering high levels of hydrocarbons in wash water.
- Recover oil from oily sludges.

Appendix 7.0

Waste Listings

7.1 Listed Wastes

In all cases, it is the generator's responsibility to ensure that all wastes are characterized and classified as well as treated and disposed of correctly. Wastes listed in Section 7.4 of Appendix 7.0, *Waste Management Table,* have been characterized and classified based on historical knowledge, previous testing, and a known origin of waste streams. The purpose of this waste management table is to provide waste generators with some common acceptable practices and criteria. It provides a starting point for characterization, classification, and the treatment/disposal of common oilfield waste streams.

In applying these classifications, it is imperative that generators examine their own wastes to determine if standard industry practices have resulted in the production of the waste and that their wastes fit the listed type. Any unusual operations, process, or site-specific conditions may result in a change in a waste's characteristics. Where classification of a waste is unclear, refer to AEP's *Alberta Users Guide for Waste Managers* for further information.

Waste generators are reminded to confirm with individual waste management facility operators the specific waste streams their facilities are approved to accept.

7.2 Unlisted Wastes

Waste types not listed in Section 7.4 of Appendix 7.0, *Waste Management Table*, must be classified according to Section 5.0, *Procedures for Classifying Waste*. Based on the characteristics of the waste, refer to the miscellaneous waste section in Section 7.4 of Appendix 7.0 for the EUB waste code, and refer to Appendix 3.0, *Recommended Test Methods*, for test methods.

7.3 Changes to Oilfield Waste Management Table

The *Waste Management Table*, Section 7.4 of Appendix 7.0, will be reviewed through a government/industry committee from time to time to consider requests for changes to the table.

Information required for this review will include:

- scientifically or operationally documented information on why the change should be made,
- historical analysis of the typical waste stream and its variability,

- consideration of the safety and environmental consequences of the proposed handling, treatment, and disposal of the waste, and

- consideration of any concerns of the public, the regulatory agencies, and the petroleum industry.

7.4 Waste Management Table

- It is the generators' responsibility to ensure wastes are treated and disposed of correctly. This table is based on wastes produced through the use of standard industry practices. If unusual properties are suspected to exist or the characteristics are uncertain, the general characterization method outlined in Section 6.2, *Procedures for Classifying Waste*, must be used.
- This table contains treatment and disposal information. Other issues such as worker safety, material handling, and storage should also be considered. References for these areas include CAPP's *Production Waste Management Handbook*, WHMIS and TDG. All requirements of TDG must be complied with.
- The use of the "Acceptable Practices" column does not result in the reclassification of a Dangerous Oilfield Waste or a waste indicated as "Testing Required" to a Non-Dangerous Oilfield Waste.
- Where classification of a waste is unclear, refer to AEP's *Alberta Users Guide for Waste Managers*, for further information.

EUB Waste Name [Waste Code]	**Oilfield Class**	**Common Transport Class**	**Common Criteria**	**Common/Acceptable Practices**	**Comments**
Absorbents [OILABS]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Reuse via laundering/dry-cleaning - Remove entrained liquids and landfill at an approved Class Ia, Ib or II landfill depending on specific characteristics - Thermal treatment	- Normally not a DOW (depending on flash point or ignitability or leachate). If BTEX > 1000 mg/kg, it cannot be landfilled
Acid Solutions (unneutralized) [ACID]	Dangerous Oilfield Waste	- Use classification according to parent product	corrosivity, heavy metals, flash point (if hydrocarbon present)	- Adjust pH prior to disposal (if possible) - Recover any hydrocarbons prior to disposal - Inject down EUB Class Ia disposal well (pH 4.5 - 12.5) - Inject down EUB Class Ib disposal well (pH 6.0 - 9.0) (if heavy metal content meets criteria outlined in EUB Guide G-51) - Physical/chemical treatment	- See EUB Guide G-51 for injection well requirements

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Activated Carbon [ACTCRB]	Testing Required	- Class 4.2 UN1362 N-DOW Not TDG regulated	flash point, leachate	DOW - Reuse/regenerate - Thermal treatment N-DOW - Reuse/regenerate - Co-dispose (amendment) with soil sterilant contaminated materials - Landfill at an approved Class Ia, Ib or II landfill depending on specific characteristics	- This waste may be DOW depending on leachate characteristics. If BTEX > 1000 mg/kg, it cannot be landfilled
Asbestos [ASBEST]	See comments	- Waste White Asbestos, Class 9.1, UN2590 - Waste Blue or Brown Asbestos, Class 9.1, UN2212	toxic airborne fibres	- Wet to reduce airborne dispersal and double bag - Landfill at an approved Class Ia, Ib, or II landfill (must be covered immediately upon disposal)	- See AEP's *Guidelines for the Disposal of Asbestos Waste*, August 1989
Batteries (Wet and Dry Cell) [BATT]	Wet Cell - Dangerous Oilfield Waste Dry Cell - Non-Dangerous Oilfield Waste (Unless containing KOH)	- Wet cell - Class 8(9.2), UN2794 - acid UN2795 - alkali - Dry cell - not TDG regulated (unless KOH) (NI-Cd)	- corrosivity, leachate (heavy metals)	- Recycle via battery recycler - Remove liquids (wet batteries) and neutralize - Landfill containers at an approved Class Ia, Ib, or II landfill (depending on battery type)	- Alkaline batteries may be disposed of as per "Garbage - Domestic Waste"

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Boiler Blowdown Water [BLBDWT]	See comments	- Not TDG regulated (unless contaminated with a DOW)		DOW - Reuse - Inject down EUB Class Ia or Ib disposal well (depending on heavy metals) N-DOW - Reuse - Inject down EUB Class Ia or Ib disposal well - Surface discharge (must conform with discharge criteria outlined in Section 5.2.2 of EUB Guide G-55 and be cooled to below 50°C prior to discharge)	- Normally not a DOW (unless containing Cr, V, or other additives) - See EUB Guide G-51 for injection well requirements
Catalyst (Non-Sulphur) [CATNS]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	leachate, pyrophoric characteristics	DOW - Reuse/regenerate - Containerize and landfill at an approved Class Ia or Ib landfill N-DOW - Reuse/regenerate - Containerize and landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- This waste may be DOW depending on leachate characteristics. If BTEX > 1000 mg/kg, it cannot be landfilled

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Catalyst (Sulphur) [CATSU]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	leachate , corrosivity, pyrophoric characteristics	- Reuse/regenerate - Containerize and landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics (add lime as per AEP guidelines)	- This waste may be DOW depending on leachate characteristics. If BTEX > 1000 mg/kg, it cannot be landfilled - See AEP's *Guidelines for the Disposal of Sulphur Containing Solid Wastes*, March 1983
Caustic Solutions (unneutralized, spent) [CAUS]	Dangerous Oilfield Waste	- Use classification according to parent product	corrosivity	- Adjust pH prior to disposal (if possible) - Inject down EUB Class Ia disposal well (pH 4.5 - 12.5) - Inject down EUB Class Ib disposal well (ph 6.0 - 9.0) - Physical/chemical treatment	- May be Waste Type 203 (if used to clean heat exchangers that possess lead-containing materials [i.e. solder, adhesives]) - See EUB Guide G-51 for injection well requirements
Cement (Returns Dry) [Cement]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Crush material and bury on lease with at least 1 meter of cover - Landfill at an approved Class Ia, Ib, I,I or III landfill - Incorporate material into gravel on site or on entrance road	
Chemicals (Inorganic) [INOCHM]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	Dangerous when wet, oxidizer, toxicity, corrosivity, leachate	- Disposal practice will vary with specific chemical (consideration of compatability and solubility) - Reuse/recycle when possible - Contact chemical waste exchange - Physical/chemical treatment	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Chemicals (Organic) [ORGCHM]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	Flash point, oxidizer, toxicity, corrosivity, leachate	- Disposal practice will vary with specific chemical - Reuse/recycle when possible - Contact chemical waste exchange - Physical/chemical treatment - Thermal treatment	
Construction and Demolition Material [CONMAT]	See comments	- Not TDG Regulated (unless contaminated with a DOW)		DOW - Decontaminate and reuse - Landfill at an approved Class Ia or Ib landfill N-DOW - Reuse - Landfill at an approved Class Ia, Ib, II, or III landfill	- Normally not a DOW (unless contaminated with a DOW)
Contaminated Debris and Soil (Chemical/ Solvent) [SOILCH]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate, toxicity	- Disposal/treatment based on specific parameters of waste - Thermal treatment - Physical/chemical treatment - Biodegradation - Landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Contaminated Debris and Soil (Crude Oil/ Condensate) [SOILCO]	See comments	- Class 4.1. UN 3175	flash point, leachate	- Biodegradation on-site (or off-site at an approved facility) - Send to an approved oilfield waste processing facility for hydrocarbon recovery - Thermal treatment	- Normally not a DOW (depending on flash point and BTEX content)
Contaminated Debris and Soil (Mercury/Metals) [SOILHM]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	leachate (heavy metals), toxicity	- Physical/chemical treatment - Landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics (Hg < 20 mg/kg - waste extract)	
Contaminated Debris and Soil (Pesticide/ Herbicide) [SOILPT]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	toxicity, leachate	- On-site treatment (with activated carbon) - Landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Consult the Industrial Vegetation Management Association of Alberta's *Field Manual for Rehabilitating Soils Affected by Residual Herbicides*, April 1987
Contaminated Debris and Soil (Produced/Salt Water) [SOILPW]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- On-site treatment - Send to an approved oilfield waste processing facility for soil washing - Landfill at an approved Class Ia, Ib, or II landfill	
Contaminated Debris and Soil (Refined Fuels/Oils) [SOILRO]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Biodegradation on-site (or off-site at an approved facility) - Send to an approved oilfield waste processing facility - Thermal treatment	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Contaminated Debris and Soil (Sulphur) [SOILSU]	Non-Dangerous Oilfield Waste	- Not TDG Regulated (unless contaminated with a DOW)		- On-site treatment - Landfill at an approved Class Ia, Ib, or II landfill (add lime to neutralize at time of burial)	- See AEP's *Guidelines for the Disposal of Sulphur Containing Solid Wastes*, March 1983
Corrosion Inhibitor/Oxygen Scavenger Solutions [CORINH]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	heavy metals	- Inject down EUB Class Ib disposal well (if heavy metal limits are not exceeded) - Inject down EUB Class Ia disposal well (if heavy metal limits exceeded)	- See EUB Guide G-51 for injection well requirements
Crude Oil/Condensate Emulsions (residuals after treatment) [COEMUL]	See comments	- Class 3, UN1267	flash point, leachate	- Send to an approved oilfield waste processing facility - Inject down EUB Class Ia or Ib disposal well - Cavern disposal - Thermal treatment - Biodegradation facility	- Normally not a DOW (depending on flash point and BTEX content) - All reasonable efforts must be made to recover hydrocarbon prior to disposal - See EUB Guide G-51 for injection well requirements
Dessicant [DESICT]	Testing required	DOW - Class 9.3 NA 9500 N-DOW - Not TDG regulated	corrosivity, flash point, leachate	DOW - Reuse/regenerate - Containerize and landfill at an approved Class Ia or Ib landfill N-DOW - Reuse/regenerate - Recycle (construction fill) - Containerize and landfill at an approved Class Ia, Ib or II landfill	- This waste may be DOW depending on leachate characteristics (BTEX). If BTEX > 1000 mg/kg, it cannot be landfilled

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Dimethyl Disulphide Solutions [DMDS]	Dangerous Oilfield Waste	- Class 3, UN 2331	flash point, toxicity	- Reuse if possible - Return to supplier - Inject down EUB Class Ia disposal well	
Drilling Sump Materials (Gel Chem) [SUMPGL]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Disposal in accordance with EUB Guide G- 50 (Revised)	- See EUB Guide G-50 (Revised) for specific disposal requirements
Drilling Sump Materials (Hydrocarbon) [SUMPIN]	See comments	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Disposal in accordance with EUB Guide G-50 (Revised)	- Normally not a DOW (depending on flash point and BTEX) - Obtain EUB approval prior to disposal - See EUB Guide G-50 (Revised) for specific disposal requirements
Drilling Sump Materials (KCL) [SUMPKC]	Non-Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations		- Disposal in accordance with EUB Guide G-50 (Revised)	- See EUB Guide G-50 (Revised) for specific disposal requirements - Obtain EUB approval prior to disposal
Filter Backwash Liquids (Gas Sweetening) [FLBWSW]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	leachate	- Inject down EUB Class Ia or Ib disposal well	- See EUB Guide G-51 for injection well requirements

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Filter Backwash Liquids (Water Treatment) [FLBWWT]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Reuse - Recycle (Land irrigation) - Return to source - Inject down EUB Class Ia or Ib disposal well	- See EUB Guide G-51 for injection well requirements - High sediment and organic content would require downhole injection
Filters Glycol [FILGLY]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, pyrophoric characteristics, leachate	- Recycle (metal recovery) - Thermal treatment - Drain liquids, containerize to prevent contact with air and landfill at an approved Class Ia or Ib landfill	- CAPP has developed a sampling and testing protocol for waste filters - Recovered entrained liquids are DOW and should be recycled or injected down an EUB Class Ia or Ib disposal well - See EUB Guide G-51 for injection well requirements
Filters (Media) - Water Treatment [FILWTT]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	DOW - Reuse/regenerate - Containerize and landfill at an approved Class Ia or Ib landfill N-DOW - Reuse/regenerate - Recycle (construction fill) - Containerize and landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- This waste may be DOW depending on leachate characteristics. If BTEX > 1000 mg/kg, it cannot be landfilled

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Filters - Air Pollution Control [FILAPC]	Testing required	- Dependent on specific waste characteristics, consult TDG Regulations		- Biodegradation - Thermal treatment - Landfill to an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Normally not a DOW (depending on leachate characteristics)
Filters - Gas Sweetening (MEA, DEA, MDEA, Sulphinol) [FILSWT]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, pyrophoric characteristics, leachate	- Recycle (metal recovery) - Thermal treatment - Drain liquids, containerize to prevent contact with air and landfill at an approved Class Ia or Ib landfill	- CAPP has developed a sampling and testing protocol for waste filters - Recovered entrained liquids are DOW and should be recycled or injected down an EUB Class Ia or Ib disposal well - See EUB Guide G-51 for injection well requirements
Filters - Lube Oil (Waste Type 201) [FILLUB]	Undrained - Dangerous Oilfield Waste Drained - Non-Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Recycle (metal recovery) - Thermal treatment - Drain liquids, landfill at an approved Class Ia or Ib landfill	- CAPP has developed a sampling and testing protocol for waste filters - Internal combustion engine lube oil filters are N-DOW if they are fully drained and have a drainage efficiency (DE) > 0.5 $DE = \frac{\text{Undrained weight - drained weight}}{\text{Undrained weight - new filter weight}}$ - Recovered entrained liquids are DOW and should be recycled or injected down an EUB Class Ia or Ib disposal well - See EUB Guide G-51 for injection well requirements

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Filters - Methanol [FILMTH]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Recycle (metal recovery) - Thermal treatment - Drain liquids, landfill at an approved Class Ia or Ib landfill	- CAPP has developed a sampling and testing protocol for waste filters - Recovered entrained liquids are DOW and should be recycled or injected down an EUB Class Ia or Ib disposal well - See EUB Guide G-51 for injection well requirements
Filters - Other (Raw/Fuel Gas, NGL's) [FILOTH]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, pyrophoric characteristics, leachate	- Recycle (metal recovery) - Thermal treatment - Drain liquids, containerize to prevent contact with air and landfill at an approved Class Ia or Ib landfill	- CAPP has developed a sampling and testing protocol for waste filters - Recovered entrained liquids are DOW and should be recycled or injected down an EUB Class Ia or Ib disposal well - See EUB Guide G-51 for injection well requirements
Filters - Produced/ Process Water [FILPWT]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, pyrophoric characteristics, leachate	- Recycle (metal recovery) - Thermal treatment - Drain liquids, containerize to prevent contact with air and landfill at an approved Class Ia or Ib landfill	- CAPP has developed a sampling and testing protocol for waste filters - Recovered entrained liquids may be DOW and should be injected down an EUB Class Ia or Ib disposal well - See EUB Guide G-51 for injection well requirements
Filters -Raw/ Fresh Water [FILFWT]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Landfill at an approved Class Ia, Ib, II, or III landfill	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Frac Sand - Non-Radioactive [FRCSND]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Recycle (return to supplier) - Send to an approved oilfield waste processing facility for hydrocarbon recovery - Containerize and landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Normally not a DOW (depending on flash point or leachate characteristics). If BTEX > 1000 mg/kg, the waste cannot be landfilled
Frac Sand-Radioactive (Plus other Radioactive Diagnostic Materials) [FRSDR]	See Comments	- Class 7	leachate	- Recycle (return to supplier) - Bury on-site in accordance with Atomic Energy Control Board Guidelines	- See Part F, Section 31.0 for specific disposal procedures - Radioactive materials must not be handled at a waste processing facility and cannot be road disposed - Radioactive frac sand is regulated by the Atomic Energy Control Board (AECB). AECB approval is required for any transportation or disposal of the waste - Waste may be DOW after radioactive decay (heavy metal and radioactive tracer leachate characteristics)
Garbage/Domestic Waste [DOMWST]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Implement the 4R's to reduce volumes (see Appendix 6) - Landfill at an approved Class Ia, Ib, II, or III landfill	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Glycol Solutions (Containing Lead or other Heavy Metals) (Waste Type 202) [GLYCHM]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, toxicity (heavy metals)	- Recycle - Inject down EUB Class Ia disposal well (glycol < 40 per cent by mass)	- Glycol solutions from vessels containing lead solder - Identified as Waste Type #202 in AEP's *Alberta Users Guide for Waste Managers*, May 1995 - See EUB Guide G-51 for injection well requirements
Glycol Solutions (No Heavy Metals) [GLYC]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, toxicity	- Recycle - Inject down EUB Class Ia or Ib disposal well (glycol < 40 per cent by mass)	- May be a DOW depending on flash point and toxicity - See EUB Guide G-51 for injection well requirements
Hydraulic and Transmission Oil [HYDOIL]	See Comments	- Not TDG Regulated (unless contaminated with a DOW)	heavy metals	- Direct to a licensed lube oil recycling firm - Thermal treatment	- Normally not a DOW (depending on heavy metal content; i.e. Va, V)
Hydrotest Fluids - Methanol [METHNL]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, toxicity	- Reuse - Recycle - Inject down EUB Class Ia or Ib disposal well (organics < 10 per cent by mass)	- See EUB Guide G-51 for injection well requirements

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Incinerator Ash [INCASH]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	leachate (heavy metals)	DOW - Landfill at an approved Class Ia or Ib landfill N-DOW - Recycle (construction fill) - Landfill at an approved Class Ia, Ib, or II landfill - Physical/chemical treatment	
Ion Exchange Resin [IEXRES]	Non-Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations		- Containerize and landfill at an approved Class Ia, Ib, or II landfill	
Ion Exchange Resin Regenerant Liquids [IEXLIQ]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations		- Inject down EUB Class Ia disposal well (pH 4.5 - 12.5) - Inject down EUB Class Ib disposal well (pH 6.0 - 9.0)	- Normally not a DOW (depending on pH) - See EUB Guide G-51 for injection well requirements
Iron Sponge [IRNSPG]	Dangerous Oilfield Waste	- Class 4.2, UN1376	pyrophoric characteristics, leachate	- Keep wet to avoid spontaneous combustion; isolate from acidic solutions - Reuse/regenerate - Landfill at an approved Class Ia or Ib landfill (add lime or equivalent at time of burial to neutralize)	- Waste may be susceptible to spontaneous combustion - this material should be kept wet at all times - See AEP's *Guidelines for the Disposal of Sulphur Containing Solid Wastes*

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Lead Based Products (H_2S Sensing Tape) [LDTAPE]	Dangerous Oilfield Waste	- Class 6.1 (9.2), UN1616	heavy metals (Pb)	- Landfill at an approved Class Ia or Ib landfill	
Lead Based Products (Pipe Dope/Greases) [LDDOPE]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	heavy metals (Pb)	- Recycle (if possible) - Thermal treatment - Landfill at an approved Class Ia or Ib landfill	
Lubricating Oil (Hydrocarbon and Synthetic) [LUBOIL]	See Comments	- Not TDG Regulated (unless contaminated with a DOW)	heavy metals, flash point	- Direct to a licensed lube oil recycling facility - Thermal treatment	- Normally not a DOW (depending on heavy metal content; i.e. Va, V)
Metal (Scrap) [SMETAL]	See Comments	- Not TDG Regulated (unless contaminated with a DOW)		DOW - Decontaminate and recycle via a scrap metal dealer - Landfill at an approved Class Ia or Ib landfill N-DOW - Recycle via a scrap metal dealer - Landfill at an approved Class Ia, Ib, II, or III landfill	- Normally not a DOW (unless contaminated with sulphur, chemicals, oil, or other DOW wastes)

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Naturally Occurring Radioactive Materials - NORMs [NORM]	Dangerous Oilfield Waste	- Class 7	toxicity	- General disposal guidelines as given in the Alberta Labour Guidelines *Guidelines for the Handling of Naturally Occurring Radioactive Materials (NORM) in Western Canada*	- See Part F, Section 31.0 for specific disposal procedures - General guidelines for the handling and disposal of NORM waste have been developed by the Western Canada NORM Committee. *Guidelines for the Handling of Naturally Occurring Radioactive Materials (NORM) in Western Canada* are available from Alberta Labour
Paints [WPAINT]	Dangerous Oilfield Waste	- Class 3, UN1263 (if flammable) - Class 8, UN3066 (if corrosive)	toxicity, flash point, heavy metals	- Physical/chemical treatment - Thermal treatment - Recycle (if possible) - Approved toxic roundup (if small volumes)	
Pesticides/ Herbicides [PSTHRB]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	toxicity	- Avoid excessive volumes - Waste material exchange programs - Thermal treatment - Approved toxic roundup (if small volumes)	- Utilize third party certified applicators for the application and disposal of pesticides when possible
Pigging Waste (Liquid and Wax) [PIGWST]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, pyrophoric characteristics	- Send to an approved oilfield waste processing facility for hydrocarbon recovery - Thermal treatment - Cavern disposal - Landfill at an approved Class Ia or Ib landfill (must be solid)	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Polychlorinated Biphenyls (PCBs) Askarel Liquids [PCBLIQ]	Dangerous Oilfield Waste	- Class 9.1, 9.2, UN2315	toxicity	- Direct to an approved hazardous waste disposal facility	
Polychlorinated Biphenyls (PCBs) - Contaminated Solids < 50 ppm [PCBSLF]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Landfill at an approved Class Ia or Ib landfill	
Polychlorinated Biphenyls (PCBs) - Contaminated Solids > 1000 ppm [PCBSGI]	Dangerous Oilfield Waste	- Class 9.1, 9.2, UN2315	toxicity	- Direct to an approved hazardous waste disposal facility	
Polychlorinated Biphenyls (PCBs) - Contaminated Solids > 50 ppm and < 1000 ppm [PCBSLI]	Dangerous Oilfield Waste	- Class 9.1, 9.2, UN2315	toxicity	- Direct to an approved hazardous waste disposal facility - Landfill at an approved Class Ia or Ib landfill	
Polychlorinated Biphenyls (PCBs) - Fluorescent Light Ballasts [PCBBAL]	Dangerous Oilfield Waste	- Class 9.1, 9.2 UN2315	toxicity	- Direct to an approved hazardous waste disposal facility - Recycle metal component if possible	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Rags [OILRAG]	See Comments	- Not TDG regulated (unless contaminated with a DOW		- Reuse via laundering/dry-cleaning - Remove entrained liquids and landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Normally not a DOW (depending on flash point or leachate). If BTEX > 1000 mg/kg, it cannot be landfilled
Salt Heat Medium [SALT]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations		- Solubilize using an existing aqueous waste stream and inject down an EUB Class Ia or Ib disposal well - Physical/chemical treatment	- Normally not a DOW (unless a strong oxidizer such as potassium or sodium salts) - See EUB Guide G-51 for injection well requirements
Sand - Produced [SAND]	See Comments	- Class 4.1, UN3175		- Send to an approved oilfield waste processing facility for hydrocarbon recovery - Recycle (other industrial uses) - Use in road construction in accordance with EUB IL 95-04 - Cavern disposal - Landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Normally not a DOW (depending on flash point or leachate characteristics). If BTEX > 1000 mg/kg, it cannot be landfilled
Sludge - Cooling Tower [SLGCTW]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	leachate (heavy metals)	- Physical/chemical treatment - Cavern disposal	- May be Waste Type 204 if hexavalent chromium used as a biocide in cooling waters

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Sludge - Flare Pit [SLGPIT]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate, toxicity	- Disposal is based on specific waste characteristics determined from analytical or historical data - Disposal options include: - physical/chemical treatment - approved Class Ia, Ib, or II landfill depending on specific characteristics - biodegradation (on-site or off-site at an approved facility) - thermal treatment - approved oilfield waste processing facility	
Sludge - Gas Sweetening Systems [SLGSWT]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Disposal is based on specific waste characteristics determined from analytical or historical data - Disposal options include: - physical/chemical treatment - approved Class Ia or Ib landfill - biodegradation - thermal treatment	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Sludge - Glycol/Gas Drying [SLGGLY]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate, toxicity	- Disposal is based on specific waste characteristics determined from analytical or historical data - Disposal options include: - physical/chemical treatment - biodegradation - thermal treatment - inject down EUB Class Ia or Ib disposal well (glycol < 40 per cent by mass)	
Sludge - Hydrocarbon [SLGHYD]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, leachate	- Disposal is based on specific waste characteristics determined from analytical or historical data - Disposal options include: - approved oilfield waste processing facility - physical/chemical treatment - biodegradation - thermal treatment - Approved Class Ia, Ib, or II landfill depending on specific characteristics	
Sludge - Lime [SLGLIM]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	corrosivity	- Co-dispose with sulphur containing wastes or soil at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- DOW if pH > 12.5

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments

Sludge - Process [SLGPRO]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	leachate	- Disposal is based on specific waste characteristics determined from analytical or historical data
				- Disposal options include:
				  - physical/chemical treatment
				  - approved Class Ia, Ib, or II landfill depending on specific characteristics
				  - biodegradation
				  - thermal treatment	

Sludge - Sulphur [SLGSUL]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	leachate, corrosivity	- Co-dispose with slightly basic wastes or soil at an approved Class Ia, Ib, or II landfill depending on specific characteristics - Physical/chemical treatment	- See AEP's *Guidelines for the Disposal of Sulphur Containing Solid Waste*, March 1983
Solvents/Residues (Halogenated) [SOLHAL]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, toxicity, leachate	- Recycle (regenerate, alternate uses) - Thermal treatment	
Solvent/Residues (Non-Halogenated Aliphatic) [SOLALP]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, toxicity, leachate	- Recycle (regenerate, alternate uses) - Thermal treatment	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Solvents/Residues (Non-Halogenated Aromatic) [SOLARO]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, toxicity, leachate	- Recycle (regencrate, alternate uses) - Thermal treatment	
Sweetening Agents (Liquids) [SWTLIQ]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations		- Inject down an EUB Class Ia, or Ib disposal well	- Normally not a DOW (depending on leachate characteristics and flash point) - See EUB Guide G-51 for injection well requirements
Sweetening Agents (Solids) [SWTSOL]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations		- Landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Normally not a DOW (depending on leachate characteristics)
Thread Protectors - Casing/Tubing [THPROT]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Reuse (return to pipe supplier) - Recycle - Landfill at an approved Class Ia, Ib, II, or III landfill	
Treater Hay [TRTHAY]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, pyrophoric characteristics	- Direct to an approved oilfield waste processing facility for hydrocarbon recovery - Thermal treatment	- May be a DOW depending on flash point, or leachate characteristics

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Wash Fluids - Organic [WSHORG]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, halogenated organics content, toxicity	- Recycle (regenerate, alternate uses) - Recover hydrocarbons and inject down EUB Class Ia or Ib disposal well - Thermal treatment	- See EUB Guide G-51 for injection well requirements
Wash Fluids - Water [WSHWTR]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations		- Recover hydrocarbons and inject down EUB Class Ia or Ib disposal well	- Normally not a DOW (depending on organic content, flash point, pH) - See EUB Guide G-51 for injection well requirements
Water Process (with Organic Chemicals) [PWTROR]	Testing Required	- Dependent on specific waste characteristics, consult TDG Regulations	flash point, halogenated organics content, toxicity	- Inject down EUB Class Ia disposal well (pH 4.5 - 12.5) - Inject down EUB Class Ib disposal well (pH 6.0 - 9.0)	- See EUB Guide G-51 for injection well requirements
Water - Process (with Heavy Metals) [PWTRHM]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations	heavy metals, pH	- Inject down EUB Class Ia disposal well (pH 4.5 - 12.5) - Inject down EUB Class Ib disposal well (pH 6.0 - 9.0) (if heavy metal content meets criteria outlined in EUB Guide G-51)	- See EUB Guide G-51 for injection well requirements
Water - Produced (Including Brine Solutions) [WATER]	Non-Dangerous Oilfield Waste	- Not TDG Regulated (unless contaminated with a DOW)		- Recycle (waterflood) - Recover hydrocarbons and inject down EUB Class Ia, Ib, or II disposal well	- See EUB Guide G-51 for injection well requirements

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Well Workover Fluids [WWOFLD]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations	corrosivity, flash point	- Inject down EUB Class Ia disposal well (pH 4.5 - 12.5) - Inject down EUB Class Ib disposal well (pH 6.0 - 9.0) - Recover any hydrocarbons prior to disposal	- See EUB Guide G-51 for injection well requirements - Heavy metals are not normally a concern for well servicing fluids
Wood (Chemically Treated/Cooling Tower) [WOODCT]	See comments	- Dependent on specific waste characteristics, consult TDG Regulations	heavy metals, leachate	- Landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Normally not a DOW (unless in dispersed form and due to leachate characteristics and/or pentachlorophenol content)

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Empty Containers					
Aerosol Cans [EMTCON]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Recycle (if possible) - Ensure containers are empty and landfill at an approved Class Ia, Ib, or II landfill	
Barrels, Pails [EMTCON]	See Comments	- Dependent on previous contents, consult TDG regulations		- Reuse/return to supplier - Recycle (barrel/container reconditioning) - Rinse (see Section 5.3), crush and landfill at an approved Class Ia, Ib, or II landfill	- Normally not a DOW (see Section 5.3) - Containers must be completely empty (see Section 5.3)
Crude Oil Sample Bottles [EMTCON]	Non-Dangerous Oilfield Waste	- Class 3, UN1267		- Reuse - Recycle (commercial bottle washing facility or a plastic/glass recycling facility) - Rinse and landfill at an approved Class Ia, Ib, or II landfill	
Cutting Oil Tubes [EMTCON]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Landfill at an approved Class Ia, Ib, or II landfill	
Grease Cartridges [EMTCON]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Landfill at an approved Class Ia, Ib, or II landfill	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Mud Sacks - Drilling [EMTCON]	Non-Dangerous Oilfield Waste	- Not TDG Regulated		- Reuse (return to mud supplier) - Landfill at an approved Class Ia, Ib, II, or III landfill - Approved thermal treatment	
Paint Cans/Brushes [EMTCON]	See Comments	- Not TDG Regulated (if dry)	toxicity	- Allow residue to dry and landfill at an approved Class Ia, Ib, or II landfill	- Not a DOW if empty and dry
Pesticide/ Herbicide Containers [PSTCON]	Dangerous Oilfield Waste	- Dependent on specific waste characteristics, consult TDG Regulations or supplier of pesticide	toxicity	- Recycle (Pesticide container collection site) - Rinse (see Section 5.3), crush, puncture and landfill at an approved Class Ia, Ib, or II landfill with a designated pesticide container collection site	- Containers must be completely empty and rinsed (see Section 5.3)
Pipe Dope Containers/ Brushes [EMTCON]	See Comments	- Dependent on specific waste characteristics, consult TDG Regulations	heavy metals	- Reuse (if possible) - Rinse (see Section 5.3) and landfill at an approved Class Ia, Ib, or II landfill depending on specific characteristics	- Not a DOW if empty and dry
Miscellaneous Wastes					
Waste Compressed or Liquified Gases [WSTCGS]	Dependent on specific waste	- Dependent on specific waste - Class 2	dependent on specific waste	- Dependent on specific waste	
Waste Flammable Liquid [WSTFLQ]	Dependent on specific waste	- Dependent on specific waste - Class 3	flammability	- Dependent on specific waste	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Waste Flammable Solid [WSTFSD]	Dependent on specific waste	- Dependent on specific waste - Class 4	flammability	- Dependent on specific waste	
Waste Oxidizing Liquid [WSTOLQ]	Dependent on specific waste	- Dependent on specific waste - Class 5	oxidizes	- Dependent on specific waste	
Waste Oxidizing Solid [WSTOSD]	Dependent on specific waste	- Dependent on specific waste - Class 5	oxidizes	- Dependent on specific waste	
Waste Poisonous Liquid [WSTPLQ]	Dependent on specific waste	- Dependent on specific waste - Class 6	toxicity	- Dependent on specific waste	
Waste Poisonous Solid [WSTPSD]	Dependent on specific waste	- Dependent on specific waste - Class 6	toxicity	- Dependent on specific waste	
Waste Radioactive Material [WSTRDM]	Dependent on specific waste	- Dependent on specific waste - Class 7	toxicity	- Dependent on specific waste	
Waste Corrosive Liquid [WSTCLQ]	Dependent on specific waste	- Dependent on specific waste - Class 8	toxicity, corrosivity	- Dependent on specific waste	
Waste Corrosive Solid [WSTCSO]	Dependent on specific waste	- Dependent on specific waste - Class 8	corrosivity	- Dependent on specific waste	

Waste Management Table (cont'd)

EUB Waste Name [Waste Code]	Oilfield Class	Common Transport Class	Common Criteria	Common/Acceptable Practices	Comments
Waste - Miscellaneous [WSTMIS]	Dependent on specific waste	- Dependent on specific waste - Class 9		- Dependent on specific waste	

- It is the generators' responsibility to ensure wastes are treated and disposed of correctly. This table is based on wastes produced through the use of standard industry practices. If unusual properties are suspected to exist or the characteristics are uncertain, the general characterization method outlined in Section 6.2, *Procedures for Classifying Waste*, must be used.
- This table contains treatment and disposal information. Other issues such as worker safety, material handling, and storage should also be considered. References for these areas include CAPP's *Production Waste Management Handbook*, WHMIS and TDG. All requirements of TDG must be complied with.
- The use of the "Acceptable Practices" column does not result in the reclassification of a Dangerous Oilfield Waste or a waste indicated as "Testing Required" to a Non-Dangerous Oilfield Waste.
- Where classification of a waste is unclear, refer to AEP's *Alberta Users Guide for Waste Managers*, for further information.

This information from Directive 030 replaces Appendix 8.1 and 8.2 in Directive 058 (February 1, 2006)

4 Annual Oilfield Waste Disposition Reporting Instructions and Computer Data Format Changes

4.1 Instructions to Complete the Oilfield Waste Disposition Report

Overview

All licensees/approval holders (oilfield waste generators) are required to implement and maintain a waste tracking system that is capable of providing the information required for the Annual Oilfield Waste Disposition Report. The oilfield wastes are required to be tracked from the initial point of generation through to the final disposition location (cradle to grave). This report provides the EUB with annual summaries regarding the types and quantities of oilfield wastes generated, the source of the oilfield waste, and the specific disposal or treatment methods used. Licensees/approval holders that are selected to submit their annual oilfield waste disposition report are required to prepare this report in accordance with Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry (formerly Guide 58).

The following detailed information describes the changes to the table "computer data format."

Header Record Layout General Information

This section of the report is to identify the header record for the file. The following information must be entered:

- **Record Type Code:** Identifies the record type (submission by file or form) for the report header.
- **BA Code:** The code assigned by the EUB to individual companies to identify approval holders or the licensee of wells, facilities, or pipelines.
- **Waste Generation Year:** The year for which this oilfield waste disposition report applies.
- **Report ID:** Sequence associated to the waste generation year for the report.

Oilfield Waste Details

This section of the report is to identify all oilfield waste generation locations (e.g., facilities, wells, batteries, pipelines) of each oilfield waste type generated and the total quantity that was treated or disposed.

- **Licence Type:** The licence type must be identified as well (W), pipeline (P), or facility (F) to describe the licence type for the location where the oilfield waste was generated.
- **Licence Number:** The licence number for the location where the oilfield waste was generated.
- **Surface Location:** The surface location of the well or facility. (For file uploads only, either the surface location of the well or facility licence **or** the licence type and licence number may be provided.)
- **Waste Code:** EUB-assigned waste code for each specific type of oilfield waste reported.

- **Waste Volume:** Total quantity (up to 3 decimal places) of each specific oilfield waste type that was transported off site for management **or** the volume treated on site during the reporting period.
- **Waste Volume Adjustment:** The adjustment quantity, positive or negative, is required to balance the differences between the total quantities of each specific oilfield waste type sent for management and quantities received at the management location, should the quantities be different (up to 3 decimal places, e.g.,123456789.000). Negative numbers are indicated with a negative sign (-).
- **Waste Volume Units:** Units the oilfield waste type is reported in. Oilfield waste is to be reported in either cubic metres or tonnes at 101.325 kPa and 15°C. *(Note that if there are quantities of a waste stream in both tonnes and cubic metres, two separate entries must be made for that specific waste type*.)

Disposal/Treatment Details

This section of the report is to identify the disposal or treatment methods used for each specific oilfield waste type and the corresponding quantities managed.

- **Disposal/Treatment Method:** Oilfield waste disposal or treatment method used for each oilfield waste type reported.
- **Disposal/Treatment Volume:** Total quantity (up to 3 decimal places) of oilfield waste disposed or treated for the reported management method.

Disposal Methods

The purpose of this section of the report is to identify the disposal methods utilized for each specific waste type and the corresponding quantities disposed.
Note: For each waste type, the total of the quantities identified for all the disposal methods utilized must equal the total quantity disposed (reported under "Waste Details") plus or minus the reported adjustments. For waste delivered to transfer stations prior to disposal, it is the responsibility of the waste generator to obtain disposal details from the transfer station operator. Those disposal details are to be indicated in this report.

- **Waste Processing Facility:** Include all waste delivered to oilfield waste processing facilities for treatment prior to disposal.
- **Disposal Wells:** Include all waste delivered directly to disposal wells. Note: Do not include waste delivered to an oilfield waste processing facility for treatment prior to well disposal.

  Class Ia Disposal Well: Directly disposed in a Class Ia disposal well.

  Class Ib Disposal Well: Directly disposed in a Class Ib disposal well.

  Class II Disposal Well: Directly disposed in a Class II disposal well.

  Cavern: Directly disposed in a cavern.

- **Landfills:** Include all waste delivered directly to landfills. Note: Do not include waste delivered to an oilfield waste processing facility for treatment prior to landfill disposal.

  Class Ia Landfill: Directly disposed in a Class Ia landfill.

Class Ib Landfill: Directly disposed in a Class Ib landfill.

Class II Landfill: Directly disposed in a Class II landfill.

Class III Landfill: Directly disposed in a Class III landfill.

- **Biodegradation Facility:** Include all waste delivered directly to biodegradation facilities. Note: Do not include waste delivered to an oilfield waste processing facility for treatment prior to disposal at a biodegradation facility or waste treated on-site by bioremediation processes.
- **Thermal Treatment:** Include all waste delivered to or treated by fixed or mobile incinerators except waste disposed of by small batch feed and campsite incinerators.
- **Used Oil Recycler:** Include all waste delivered to facilities which collect used lubricating oils for reprocessing or fuel blending.
- **Recycling Facility:** Include all waste delivered to recycling facilities (excluding Used Oil Recyclers).
- **Swan Hills:** Include all waste delivered to the Swan Hills Hazardous Waste Treatment Centre.
- **Small Oilfield Waste Incinerators:** Include all waste disposed of by small batch feed and campsite incinerators.
- **Biodegradation (On-site):** Include all on-site waste treatment through bioremediation including biocells/biopiles and land treatment (exclude in situ).
- **Road Spread:** Include all waste disposed by road spreading.
- **Burial (On-site):** Include all waste disposed by on-site burial.
- **Transborder:** Include all waste shipped out of Alberta for disposal.
- **Others:** Include waste treated/disposed utilizing disposal methods not listed above.

4.2 Computer Data Format

Field	Start	Length	Format	Definition/Format/Usage
Header Record Layout–first row of upload file				
Record Type Code	1	3	9(3)	The code identifies the record type for the report header record. The information appears only once for the entire upload file (e.g., 001).
BA Code	4	4	X(4)	EUB-assigned company code (e.g., 0338).
Waste Generation Year	8	4	9(4)	Year for which the report applies (01 Jan – 31 Dec) (e.g., 1996).
Report ID	12	8	9(8)	Sequence associated to the reporting year for the specific report (leading zero fill) (e.g., 00000001).

(continued)

Field	Start	Length	Format	Definition/Format/Usage
Detailed Record Layout–second and each subsequent row of upload file				
Record Type Code	1	3	9(3)	The code identifies the record type for the report header record. The information appears on the second and each subsequent row of the entire upload file (e.g., 002).
BA Code	4	4	X(4)	EUB-assigned company code (e.g., 0338).
Waste Generation Year	8	4	9(4)	Year for which the report applies (01 Jan - 31 Dec) (e.g., 1996).
Report ID	12	8	9(8)	Sequence associated to the reporting year for the specific report (leading zero fill) (e.g., 00000001).
Oilfield Waste Details–an additional row for each unique waste code for a licence				
Licence Type	20	1	X(1)	This is the licence type as indicated as well (W), pipeline (P), or facility (F) to describe the licence type for where the oilfield waste was generated. Must enter W, P, or F.
Licence Number	21	9	X(9)	This is the licence number for the location where the oilfield waste was generated (e.g., 0000001).
Surface Location	30	17	X(17)	This is the complete surface location for the licence (includes Location Exception, LSD, Section, Township, Range, Meridian) (e.g., 00-11-26-045-06W4).
Waste Code	47	6	X(6)	EUB-assigned waste code (see the on-line help to download a list of waste codes).
Waste Volume	53	13	9(9)V3	Total quantity of each specific type of oilfield waste shipped or treated (up to 3 decimal places) (e.g., 123456789.000).
Waste Volume Adjustment	66	14	9(9)V3	The adjustment quantity, positive or negative, is required to balance the differences between the total quantities of each specific oilfield waste type sent for management and quantities received at the management location, should the quantities be different (up to 3 decimal places, e.g., 123456789.000). Negative numbers are indicated with a negative sign.
Waste Volume Units	80	1	X(1)	Units the oilfield waste type is reported in (cubic metres or tonnes). Must enter M or T**.**
Disposal/Treatment Details–an additional row for each unique disposal/treatment method for each oilfield waste code for each licence				
Disposal or Treatment Method	81	2	X(2)	Disposal or treatment method used for each oilfield waste type (see the on-line help to download a list of disposal or treatment methods).
Disposal or Treatment Volume	83	13	9(9)V3	Quantity of oilfield waste disposed or treated for the disposal or treatment method used (up to 3 decimal places, e.g., 123456789.000).

Fisheries and Oceans Canada / Pêches et Océans Canada

NOTIFICATION FORM

Fisheries and Oceans Canada
Northwest Terrritories Operational Statement

Version 3.0

PROPONENT INFORMATION

NAME: | STREET ADDRESS:
CITY/TOWN: | PROVINCE/TERRITORY: | POSTAL CODE:
TEL. NO. (RESIDENCE): | TEL. NO. (WORK):
FAX NO: | EMAIL ADDRESS:

CONTRACTOR INFORMATION (provide this information if a Contractor is working on behalf of the Proponent)

NAME: | STREET ADDRESS:
CITY/TOWN: | PROVINCE/TERRITORY: | POSTAL CODE:
TEL. NO. (RESIDENCE): | TEL. NO. (WORK):
FAX NO: | EMAIL ADDRESS:

PROJECT INFORMATION

Select Operational Statements that are being used (check all applicable boxes):

- ❒ Bridge Maintenance
- ❒ Clear-Span Bridges
- ❒ Culvert Maintenance
- ❒ Dock and Boathouse Construction
- ❒ High-Pressure Directional Drilling
- ❒ Ice Bridges and Snow Fills
- ❒ Isolated or Dry Open-cut Stream Crossings
- ❒ Maintenance of Riparian Vegetation in Existing Rights-of-Way
- ❒ Moorings
- ❒ Overhead Line Construction
- ❒ Punch & Bore Crossings
- ❒ Routine Maintenance Dredging
- ❒ Temporary Stream Crossing
- ❒ Underwater Cables

Select the type of water body or watercourse at or near your project:

- ❒ River, Stream, Creek
- ❒ Lake (8 hectares or greater)
- ❒ Pond or wetland (pond is less than 8 hectares)
- ❒ Marine (Ocean or Sea)
- ❒ Estuary

PROJECT LOCATION(S) (fill out this section if the project location is different from Proponent Information; append multiple project locations on an additional sheet if necessary)

Name of water body or watercourse	Coordinates of the Project (UTM co-ordinate or Degrees, Minutes, Seconds), if available Easting: Northing: Latitude: Longitude:
Legal Description (Plan, Block, Lot, Municipality, Township)	Directions to Access the Project Site (i.e., Route or highway number, etc.)
Proposed Start Date (YYYY/MM/DD):	Proposed Completion Date (YYYY/MM/DD):

We ask that you notify DFO, preferably 10 working days before starting your work, by filling out and sending in, by mail or by fax, this notification form to the DFO office in your area. This information is requested in order to evaluate the effectiveness of the work carried out in relation to the Operational Statement.

I, ____________________________ (print name) certify that the information given on this form is, to the best of my knowledge, correct and complete.

Signature ____________________________ Date ______________

Note: If you cannot meet all of the conditions and cannot incorporate all of the measures in the Operational Statement then your project may result in a violation of subsection 35(1) of the *Fisheries Act* and you could be subject to enforcement action. In this case, you should contact the DFO office in your area if you wish to obtain DFO's opinion on the possible options you should consider to avoid contravention of the *Fisheries Act*.

Information about the above-noted proposed work or undertaking is collected by DFO under the authority of the *Fisheries Act* for the purpose of administering the fish habitat protection provisions of the *Fisheries Act*. Personal information will be protected under the provisions of the *Privacy Act* and will be stored in the Personal Information Bank DFO-SCI-605. Under the *Privacy Act*, individuals have a right to, and on request shall be given access to, any personal information about them contained in a personal information bank. Instructions for obtaining personal information are contained in the Government of Canada's Info Source publications available at **www.infosource.gc.ca** or in Government of Canada offices. Information other than "personal" information may be accessible or protected as required by the provisions of the *Access to Information Act*.

Canada

FISHERIES AND OCEANS CANADA OFFICES IN NORTHWEST TERRITORIES

Yellowknife Area Office
Fisheries and Oceans Canada
Suite 101 - Diamond Plaza
5204 - 50th Ave.
Yellowknife, NT X1A 1E2
Phone: (867) 669-4900
Fax: (867) 669-4940

Inuvik District Office
Fisheries and Oceans Canada
Box 1871
Inuvik, NT X0E 0T0
Phone: (867) 777-7500
Fax: (867) 777-7501

Aussi disponible en français

http://www.dfo-mpo.gc.ca/oceans-habitat/habitat/modernizing-moderniser/epmp-pmpe/index_f.asp

DFO/2007-1329

Registration
SOR/2009-315 November 26, 2009

CANADA OIL AND GAS OPERATIONS ACT

Canada Oil and Gas Drilling and Production Regulations

P.C. 2009-1890 November 26, 2009

Whereas, pursuant to subsection 15(1) of the *Canada Oil and Gas Operations Act*[a], a copy of the proposed *Canada Oil and Gas Drilling and Production Regulations*, substantially in the annexed form, was published in the *Canada Gazette*, Part I on April 18, 2009 and interested persons were given an opportunity to make representations to the Minister of Natural Resources and the Minister of Indian Affairs and Northern Development with respect to the proposed Regulations;

Therefore, Her Excellency the Governor General in Council, on the recommendation of the Minister of Natural Resources and the Minister of Indian Affairs and Northern Development, pursuant to subsection 14(1)[b] of the *Canada Oil and Gas Operations Act*[a], hereby makes the annexed *Canada Oil and Gas Drilling and Production Regulations*.

CANADA OIL AND GAS DRILLING AND PRODUCTION REGULATIONS

INTERPRETATION

1. (1) The following definitions apply in these Regulations.

"abandoned", in relation to a well, means a well or part of a well that has been permanently plugged. (*abandonné*)

"Act" means the *Canada Oil and Gas Operations Act*. (*Loi*)

"artificial island" means a humanly constructed island to provide a site for the exploration and drilling, or the production, storage, transportation, distribution, measurement, processing or handling, of oil or gas. (*île artificielle*)

"authorization" means an authorization issued by the Board under paragraph 5(1)(*b*) of the Act. (*autorisation*)

"barrier" means any fluid, plug or seal that prevents gas or oil or any other fluid from flowing unintentionally from a well or from a formation into another formation. (*barrière*)

"Board" means the National Energy Board established by section 3 of the *National Energy Board Act*. (*Office*)

"casing liner" means a casing that is suspended from a string of casing previously installed in a well and does not extend to the wellhead. (*tubage partiel*)

"commingled production" means production of oil and gas from more than one pool or zone through a common well-bore or flow line without separate measurement of the production from each pool or zone. (*production mélangée*)

"completed", in relation to a well, means a well that is prepared for production or injection operations. (*complété*)

[a] R.S., c. 0-7; S.C. 1992, c. 35, s. 2
[b] S.C. 1994, c. 10, s. 7

Enregistrement
DORS/2009-315 Le 26 novembre 2009

LOI SUR LES OPÉRATIONS PÉTROLIÈRES AU CANADA

Règlement sur le forage et la production de pétrole et de gaz au Canada

C.P. 2009-1890 Le 26 novembre 2009

Attendu que, conformément au paragraphe 15(1) de la *Loi sur les opérations pétrolières au Canada*[a], le projet de règlement intitulé *Règlement sur le forage et la production de pétrole et de gaz au Canada*, conforme en substance au texte ci-après, a été publié dans la *Gazette du Canada* Partie I, le 18 avril 2009 et que les intéressés ont ainsi eu la possibilité de présenter leurs observations à cet égard à la ministre des Ressources naturelles et au ministre des Affaires indiennes et du Nord canadien,

À ces causes, sur recommandation de la ministre des Ressources naturelles et du ministre des Affaires indiennes et du Nord canadien et en vertu du paragraphe 14(1)[b] de la *Loi sur les opérations pétrolières au Canada*[a], Son Excellence la Gouverneure générale en conseil prend le *Règlement sur le forage et la production de pétrole et de gaz au Canada*, ci-après.

RÈGLEMENT SUR LE FORAGE ET LA PRODUCTION DE PÉTROLE ET DE GAZ AU CANADA

DÉFINITIONS ET INTERPRÉTATION

1. (1) Les définitions qui suivent s'appliquent au présent règlement.

« abandonné » Se dit d'un puits ou d'une partie d'un puits qui a été obturé de façon permanente. (*abandoned*)

« approbation relative à un puits » Approbation accordée par l'Office en vertu de l'article 13. (*well approval*)

« autorisation » Autorisation délivrée par l'Office en vertu de l'alinéa 5(1)*b*) de la Loi. (*authorization*)

« barrière » Tout fluide, bouchon ou autre dispositif d'étanchéité qui empêche du gaz, du pétrole ou tout autre fluide de s'écouler accidentellement soit d'une formation à une autre soit d'un puits. (*barrier*)

« blessure entraînant une perte de temps de travail » Blessure qui empêche un employé de se présenter au travail ou de s'acquitter efficacement de toutes les fonctions liées à son travail habituel les jours suivant le jour de l'accident, qu'il s'agisse ou non de jours ouvrables pour lui. (*lost or restricted workday injury*)

« blessure sans gravité » Lésion professionnelle, autre qu'une blessure entraînant une perte de temps de travail, qui fait l'objet d'un traitement médical ou de premiers soins. (*minor injury*)

« câble » Câble renfermant un fil conducteur et servant à la manœuvre d'instruments de sondage ou d'autres outils dans un puits. (*wire line*)

« câble lisse » Câble en acier monobrin servant à la manœuvre d'outils dans un puits. (*slick line*)

[a] L.R., ch. 0-7; L.C. 1992, ch. 35, art. 2
[b] L.C. 1994, ch. 10, art. 7

"completion interval" means a section within a well that is prepared to permit the

(*a*) production of fluids from the well;

(*b*) observation of the performance of a reservoir; or

(*c*) injection of fluids into the well. (*intervalle de complétion*)

"conductor casing" means the casing that is installed in a well to facilitate drilling of the hole for the surface casing. (*tubage initial*)

"development plan" means the development plan that is approved by the Board in accordance with section 5.1 of the Act. (*plan de mise en valeur*)

"drilling program" means the program for the drilling of one or more wells within a specified area and time using one or more drilling installations and includes any work or activity related to the program. (*programme de forage*)

"environmental protection plan" means the environmental protection plan submitted to the Board under section 6. (*plan de protection de l'environnement*)

"flow allocation procedure" means the procedure to

(*a*) allocate total measured quantities of oil, gas and water produced from or injected into a pool or zone back to individual wells in a pool or zone where individual well production or injection is not measured separately; and

(*b*) allocate production to fields that are using a common storage or processing facility. (*méthode de répartition du débit*)

"flow calculation procedure" means the procedure to be used to convert raw meter output to a measured quantity of oil, gas or water. (*méthode de calcul du débit*)

"flow system" means the flow meters, auxiliary equipment attached to the flow meters, fluid sampling devices, production test equipment, the master meter and meter prover used to measure and record the rate and volumes at which fluids are

(*a*) produced from or injected into a pool;

(*b*) used as a fuel;

(*c*) used for artificial lift; or

(*d*) flared or transferred from a production installation. (*système d'écoulement*)

"fluid" means gas, liquid or a combination of the two. (*fluide*)

"formation flow test" means an operation

(*a*) to induce the flow of formation fluids to the surface of a well to procure reservoir fluid samples and determine reservoir flow characteristics; or

(*b*) to inject fluids into a formation to evaluate injectivity. (*essai d'écoulement de formation*)

"incident" means

(*a*) any event that causes

(i) a lost or restricted workday injury,

(ii) death,

(iii) fire or explosion,

(iv) a loss of containment of any fluid from a well,

(v) an imminent threat to the safety of a person, installation or support craft, or

(vi) pollution;

(*b*) any event that results in a missing person; or

(*c*) any event that causes

« cessation » S'entend de l'abandon, de la complétion, ou de la suspension de l'exploitation d'un puits. (*termination*)

« complété » Se dit d'un puits qui a été préparé en vue de travaux de production ou d'injection. (*completed*)

« conditions environnementales » Conditions météorologiques, océanographiques et conditions connexes, notamment l'état des glaces, qui peuvent influer sur les activités visées par l'autorisation. (*physical environmental conditions*)

« contrôle d'un puits » Contrôle de la circulation des fluides qui pénètrent dans un puits ou en sortent. (*well control*)

« couche » Couche ou séquence de couches, y compris, pour l'application de la définition de « production mélangée », de l'article 7, du paragraphe 61(2), des articles 64 à 66 et 73, du paragraphe 82(2) et de l'article 85, toute couche désignée comme telle par l'Office en vertu de l'article 4. (*zone*)

« date de libération de l'appareil de forage » Date à laquelle un appareil de forage a exécuté des travaux pour la dernière fois dans un puits. (*rig release date*)

« déchets » Détritus, rebuts, eaux usées, fluides résiduels ou autres matériaux inutilisables produits au cours des activités de forage, des travaux relatifs à un puits ou des travaux de production, y compris les fluides et les déblais de forage usés ou excédentaires, ainsi que l'eau produite. (*waste material*)

« essai au prorata » Essai effectué dans un puits d'exploitation visé par un plan de mise en valeur pour en mesurer le débit des fluides produits à des fins de répartition. (*proration test*)

« essai d'écoulement de formation » Opération visant, selon le cas :

a) à provoquer l'écoulement des fluides de formation vers la surface d'un puits afin d'obtenir des échantillons des fluides du réservoir et de déterminer les caractéristiques de l'écoulement de celui-ci;

b) à injecter des fluides dans une formation afin d'évaluer l'injectivité. (*formation flow test*)

« exploitant » Personne qui est titulaire à la fois d'un permis de travaux délivré en vertu de l'alinéa 5(1)*a*) de la Loi et d'une autorisation. (*operator*)

« fluide » Gaz, liquide ou combinaison des deux. (*fluid*)

« fond marin » Partie de la croûte terrestre formant le fond des océans. (*seafloor*)

« île artificielle » Île construite de toutes pièces afin de servir d'emplacement pour la prospection et le forage, ou pour la production, le stockage, le transport, la distribution, la mesure, le traitement ou la manutention du pétrole ou du gaz. (*artificial island*)

« incident »

a) Événement qui entraîne l'une ou l'autre des situations suivantes :

(i) une blessure entraînant une perte de temps de travail,

(ii) une perte de vie,

(iii) un incendie ou une explosion,

(iv) une défaillance du confinement d'un fluide provenant d'un puits,

(v) une menace imminente à la sécurité d'une personne, d'une installation ou d'un véhicule de service,

(vi) de la pollution;

b) événement à la suite duquel une personne est portée disparue;

(i) the impairment of any structure, facility, equipment or system critical to the safety of persons, an installation or support craft, or

(ii) the impairment of any structure, facility, equipment or system critical to environmental protection. (*incident*)

"lost or restricted workday injury" means an injury that prevents an employee from reporting for work or from effectively performing all the duties connected with the employee's regular work on any day subsequent to the day on which the injury occurred whether or not that subsequent day is a working day for that employee. (*blessure entraînant une perte de temps de travail*)

"minor injury" means an employment injury for which medical treatment or first aid is provided and excludes a lost or restricted workday injury. (*blessure sans gravité*)

"multi-pool well" means a well that is completed in more than one pool. (*puits à gisements multiples*)

"natural environment" means the physical and biological environment. (*milieu naturel*)

"near-miss" means an event that would likely cause an event set out in paragraph (*a*) of the definition of "incident", but does not due to particular circumstances. (*quasi-incident*)

"operator" means a person that holds an operating licence under paragraph 5(1)(*a*) of the Act and an authorization. (*exploitant*)

"permafrost" means the thermal condition of the ground when its temperature remains at or below 0°C for more than one year. (*pergélisol*)

"physical environmental conditions" means the meteorological, oceanographic and related physical conditions, including ice conditions, that might affect a work or activity that is subject to an authorization. (*conditions environnementales*)

"pollution" means the introduction into the natural environment of any substance or form of energy outside the limits applicable to the activity that is subject to an authorization, including spills. (*pollution*)

"production control system" means the system provided to control the operation of, and monitor the status of, equipment for the production of oil and gas, and includes the installation and workover control system. (*système de contrôle de la production*)

"production project" means an undertaking for the purpose of developing a production site on, or producing oil or gas from, a pool or field, and includes any work or activity related to the undertaking. (*projet de production*)

"proration test" means, in respect of a development well to which a development plan applies, a test conducted to measure the rates at which fluids are produced from the well for allocation purposes. (*essai au prorata*)

"recovery" means the recovery of oil and gas under reasonably foreseeable economic and operational conditions. (*récupération*)

"relief well" means a well drilled to assist in controlling a blow-out in an existing well. (*puits de secours*)

"rig release date" means the date on which a rig last conducted well operations. (*date de libération de l'appareil de forage*)

"safety plan" means the safety plan submitted to the Board under section 6. (*plan de sécurité*)

"seafloor" means the surface of all that portion of land under the sea. (*fond marin*)

c) événement qui nuit :

(i) soit au fonctionnement d'une structure, de matériel, d'un équipement ou d'un système essentiel au maintien de la sécurité des personnes ou de l'intégrité d'une installation ou d'un véhicule de service,

(ii) soit au fonctionnement d'une structure, de matériel, d'un équipement ou d'un système essentiel à la protection de l'environnement. (*incident*)

« intervalle de complétion » Section aménagée dans un puits en vue de l'une des activités suivantes :

a) la production de fluides à partir du puits;

b) l'observation du rendement d'un réservoir;

c) l'injection de fluides dans le puits. (*completion interval*)

« Loi » La *Loi sur les opérations pétrolières au Canada*. (*Act*)

« méthode de calcul du débit » Méthode utilisée pour convertir le débit brut d'un compteur en une quantité mesurée de pétrole, de gaz ou d'eau. (*flow calculation procedure*)

« méthode de répartition du débit » Méthode servant à :

a) répartir les quantités mesurées totales de pétrole, de gaz et d'eau qui sont produits par un gisement ou une couche ou y sont injectés, entre les différents puits faisant partie d'un gisement ou d'une couche où la production ou l'injection n'est pas mesurée séparément pour chaque puits;

b) répartir la production entre les champs où le stockage ou le traitement se fait dans une installation commune. (*flow allocation procedure*)

« milieu naturel » Milieu physique et biologique. (*natural environment*)

« Office » L'Office national de l'énergie, constitué par l'article 3 de la *Loi sur l'Office national de l'énergie*. (*Board*)

« pergélisol » Condition thermique du sol lorsque sa température est égale ou inférieure à 0 °C pendant plus d'un an. (*permafrost*)

« plan de mise en valeur » Plan de mise en valeur approuvé par l'Office aux termes de l'article 5.1 de la Loi. (*development plan*)

« plan de protection de l'environnement » Plan de protection de l'environnement remis à l'Office conformément à l'article 6. (*environmental protection plan*)

« plan de sécurité » Plan en matière de sécurité remis à l'Office conformément à l'article 6. (*safety plan*)

« pollution » Introduction dans le milieu naturel de toute substance ou forme d'énergie au-delà des limites applicables à l'activité visée par l'autorisation. La présente définition vise également les rejets. (*pollution*)

« production mélangée » Production de pétrole et de gaz provenant de plusieurs gisements ou couches et circulant dans la même conduite ou dans le même trou de sonde, sans mesurage distinct de la production de chaque gisement ou couche. (*commingled production*)

« programme de forage » Programme relatif au forage d'un ou de plusieurs puits, dans une région donnée et au cours d'une période déterminée, au moyen d'une ou de plusieurs installations de forage. Y sont assimilées les activités connexes au programme. (*drilling program*)

« projet de production » Projet visant la mise en valeur d'un emplacement de production ou la production de pétrole ou de gaz à partir d'un champ ou d'un gisement, y compris les activités connexes au projet. (*production project*) "slick line" means a single steel cable used to run tools in a well. (*câble lisse*)

"support craft" means a vessel, vehicle, aircraft, standby vessel or other craft used to provide transportation for or assistance to persons on the site where a work or activity is conducted. (*véhicule de service*)

"surface casing" means the casing that is installed in a well to a sufficient depth, in a competent formation, to establish well control for the continuation of the drilling operations. (*tubage de surface*)

"suspended", in relation to a well or part of a well, means a well or part of a well in which drilling or production operations have temporarily ceased. (*suspension de l'exploitation*)

"termination" means the abandonment, completion or suspension of a well's operations. (*cessation*)

"waste material" means any garbage, refuse, sewage or waste well fluids or any other useless material that is generated during drilling, well or production operations, including used or surplus drilling fluid and drill cuttings and produced water. (*déchets*)

"well approval" means the approval granted by the Board under section 13. (*approbation relative à un puits*)

"well-bore" means the hole drilled by a bit in order to make a well. (*trou de sonde*)

"well control" means the control of the movement of fluids into or from a well. (*contrôle d'un puits*)

"well operation" means the operation of drilling, completion, recompletion, intervention, re-entry, workover, suspension or abandonment of a well. (*travaux relatifs à un puits*)

"wire line" means a line that contains a conductor wire and that is used to run survey instruments or other tools in a well. (*câble*)

"workover" means an operation on a completed well that requires removal of the Christmas tree or the tubing. (*reconditionnement*)

"zone" means any stratum or any sequence of strata and includes, for the purposes of the definition "commingled production", section 7, subsection 61(2), sections 64 to 66 and 73, subsection 82(2) and section 85, a zone that has been designated as such by the Board under section 4. (*couche*)

(2) In these Regulations, "delineation well", "development well" and "exploratory well" have the same meaning as in subsection 101(1) of the *Canada Petroleum Resources Act*.

(3) In these Regulations, "drilling installation", "drilling rig", "drilling unit", "drill site", "installation", "production installation", "production operation", "production site" and "subsea

« puits à gisements multiples » Puits complété dans plus d'un gisement. (*multi-pool well*)

« puits de secours » Puits foré pour aider à contrôler l'éruption d'un puits existant. (*relief well*)

« quasi-incident » Événement qui serait susceptible d'entraîner une des situations visées à l'alinéa *a*) de la définition de « incident » mais qui, en raison de circonstances particulières, n'en entraîne pas. (*near-miss*)

« reconditionnement » Opération pratiquée sur un puits complété et exigeant le retrait de la tête d'éruption ou du tube. (*workover*)

« récupération » Récupération de pétrole et de gaz dans des conditions économiques et opérationnelles normalement prévisibles. (*recovery*)

« suspension de l'exploitation » S'agissant d'un puits ou d'une partie d'un puits, interruption temporaire des activités de forage ou des travaux de production. (*suspended*)

« système de contrôle de la production » Système servant au contrôle du fonctionnement de l'équipement de production de pétrole et de gaz et à la surveillance de son état, y compris le système de régulation de l'installation et du reconditionnement. (*production control system*)

« système d'écoulement » Les débitmètres et l'équipement auxiliaire qui y est fixé, les dispositifs d'échantillonnage de fluides, l'équipement pour les essais de production, le compteur principal et le compteur étalon servant à mesurer et à enregistrer le débit et le volume des fluides qui, selon le cas :

a) sont produits par un gisement ou y sont injectés;

b) sont utilisés comme combustibles;

c) sont utilisés pour l'ascension artificielle;

d) sont brûlés à la torche ou transférés d'une installation de production. (*flow system*)

« travaux relatifs à un puits » Travaux liés au forage, à la complétion, à la remise en production, au reconditionnement, à la suspension de l'exploitation, à l'abandon ou à la rentrée d'un puits ou à l'intervention dans un puits. (*well operation*)

« trou de sonde » Trou foré au moyen d'un trépan pour le creusage d'un puits. (*well-bore*)

« tubage de surface » Tubage installé assez profondément dans un puits, dans une formation compétente, pour assurer le contrôle du puits en vue de la poursuite des travaux de forage. (*surface casing*)

« tubage initial » Tubage installé dans un puits pour faciliter le forage du trou dans lequel sera introduit le tubage de surface. (*conductor casing*)

« tubage partiel » Tubage suspendu à un train de tubage installé antérieurement dans un puits et qui n'atteint pas la tête du puits. (*casing liner*)

« véhicule de service » Navire, véhicule, aéronef, navire de secours ou autre moyen de transport ou d'aide destiné aux personnes se trouvant à un emplacement où sont menées des activités. (*support craft*)

(2) Dans le présent règlement, « puits de délimitation », « puits d'exploitation » et « puits d'exploration » s'entendent au sens du paragraphe 101(1) de la *Loi fédérale sur les hydrocarbures*.

(3) Dans le présent règlement, « appareil de forage », « emplacement de forage », « emplacement de production », « installation », « installation de forage », « installation de production »,

production system" have the same meaning as in subsection 2(1) of the *Canada Oil and Gas Installations Regulations*.

(4) The following definitions apply for the purposes of paragraph 5(4)(*c*) of the Act:

"production facility" means equipment for the production of oil or gas located at a production site, including separation, treating and processing facilities, equipment and facilities used in support of production operations, landing areas, heliports, storage areas or tanks and dependent personnel accommodations, but not including any associated platform, artificial island, subsea production system, drilling equipment or diving system. (*matériel de production*)

"production platform" means a production facility and any associated platform, artificial island, subsea production system, offshore loading system, drilling equipment, facilities related to marine activities and dependent diving system. (*plate-forme de production*)

(5) For the purpose of section 5.11 of the Act, "installation" means an onshore or offshore installation.

(6) For the purpose of section 58.2 of the Act, an onshore or offshore installation is prescribed as an installation.

« système de production sous-marin », « travaux de production » et « unité de forage » s'entendent au sens du paragraphe 2(1) du *Règlement sur les installations pétrolières et gazières au Canada*.

(4) Les définitions qui suivent s'appliquent à l'alinéa 5(4)*c*) de la Loi.

« matériel de production » Équipement de production du pétrole ou du gaz se trouvant à l'emplacement de production, y compris le matériel de séparation, de traitement et de transformation, les équipements et le matériel utilisés à l'appui des travaux de production, les aires d'atterrissage, les héliports, les aires ou les réservoirs de stockage et les logements du personnel connexes. La présente définition exclut toute plate-forme, toute île artificielle, tout système de production sous-marin, tout équipement de forage et tout système de plongée connexes. (*production facility*)

« plate-forme de production » S'entend de tout matériel de production, ainsi que de tout système de production sous-marin, plate-forme, île artificielle, système de chargement extracôtier, équipement de forage, matériel lié aux activités maritimes et système de plongée non autonome connexes. (*production platform*)

(5) Pour l'application de l'article 5.11 de la Loi, « installation » s'entend d'une installation terrestre ou extracôtière.

(6) Pour l'application de l'article 58.2 de la Loi, les installations terrestres et extracôtières sont des installations désignées.

PART 1

BOARD'S POWERS

SPACING

2. The Board is authorized to make orders respecting the allocation of areas, including the determination of the size of spacing units and the well production rates for the purpose of drilling for or producing oil and gas and to exercise any powers and perform any duties that may be necessary for the management and control of oil or gas production.

NAMES AND DESIGNATIONS

3. The Board may give a name, classification or status to any well and may change that name, classification or status.

4. The Board may also

(*a*) designate a zone for the purposes of these Regulations;

(*b*) give a name to a pool or field; and

(*c*) define the boundaries of a pool, zone or field for the purpose of identifying it.

PARTIE 1

POUVOIRS DE L'OFFICE

ESPACEMENT

2. L'Office est autorisé à rendre des ordonnances concernant l'attribution de secteurs, notamment en ce qui a trait à la dimension des unités d'espacement et au taux de production des puits aux fins de forage ou de production de pétrole ou de gaz, et à exercer les attributions nécessaires à la gestion et au contrôle de la production du pétrole et du gaz.

NOMS ET DÉSIGNATIONS

3. L'Office peut attribuer un nom, une classe ou un statut à un puits et les modifier.

4. L'Office peut en outre :

a) désigner comme telle une couche pour l'application du présent règlement;

b) attribuer un nom à un gisement ou à un champ;

c) définir les limites d'un gisement, d'une couche ou d'un champ à des fins d'identification.

PART 2

MANAGEMENT SYSTEM, APPLICATION FOR AUTHORIZATION AND WELL APPROVALS

MANAGEMENT SYSTEM

5. (1) The applicant for an authorization shall develop an effective management system that integrates operations and technical

PARTIE 2

SYSTÈME DE GESTION, DEMANDE D'AUTORISATION ET APPROBATIONS RELATIVES À UN PUITS

SYSTÈME DE GESTION

5. (1) La personne qui demande une autorisation est tenue d'élaborer un système de gestion efficace qui intègre les systèmes systems with the management of financial and human resources to ensure compliance with the Act and these Regulations.

(2) The management system shall include

(*a*) the policies on which the system is based;

(*b*) the processes for setting goals for the improvement of safety, environmental protection and waste prevention;

(*c*) the processes for identifying hazards and for evaluating and managing the associated risks;

(*d*) the processes for ensuring that personnel are trained and competent to perform their duties;

(*e*) the processes for ensuring and maintaining the integrity of all facilities, structures, installations, support craft and equipment necessary to ensure safety, environmental protection and waste prevention;

(*f*) the processes for the internal reporting and analysis of hazards, minor injuries, incidents and near-misses and for taking corrective actions to prevent their recurrence;

(*g*) the documents describing all management system processes and the processes for making personnel aware of their roles and responsibilities with respect to them;

(*h*) the processes for ensuring that all documents associated with the system are current, valid and have been approved by the appropriate level of authority;

(*i*) the processes for conducting periodic reviews or audits of the system and for taking corrective actions if reviews or audits identify areas of non-conformance with the system and opportunities for improvement;

(*j*) the arrangements for coordinating the management and operations of the proposed work or activity among the owner of the installation, the contractors, the operator and others, as applicable; and

(*k*) the name and position of the person accountable for the establishment and maintenance of the system and of the person responsible for implementing it.

(3) The management system documentation shall be controlled and set out in a logical and systematic fashion to allow for ease of understanding and efficient implementation.

(4) The management system shall correspond to the size, nature and complexity of the operations and activities, hazards and risks associated with the operations.

APPLICATION FOR AUTHORIZATION

6. The application for authorization shall be accompanied by

(*a*) a description of the scope of the proposed activities;

(*b*) an execution plan and schedule for undertaking those activities;

(*c*) a safety plan that meets the requirements of section 8;

(*d*) an environmental protection plan that meets the requirements of section 9;

(*e*) information on any proposed flaring or venting of gas, including the rationale and the estimated rate, quantity and period of the flaring or venting;

opérationnels et techniques et la gestion des ressources humaines et financières pour assurer l'observation de la Loi et du présent règlement.

(2) Le système de gestion doit comprendre :

a) un énoncé des politiques qui en constituent le fondement;

b) des processus permettant de fixer des objectifs en vue d'améliorer la sécurité, la protection de l'environnement et la prévention du gaspillage;

c) des processus permettant de repérer les dangers et d'évaluer et maîtriser les risques connexes;

d) des processus permettant de veiller à ce que les membres du personnel soient formés et disposent des compétences nécessaires pour remplir leurs fonctions;

e) des processus permettant de garantir et de préserver l'intégrité du matériel, des structures, des installations, des véhicules de service et des équipements nécessaires à la sécurité, à la protection de l'environnement et à la prévention du gaspillage;

f) des processus permettant de signaler à l'interne et d'analyser les dangers, les blessures sans gravité, les incidents et les quasi-incidents, et de prendre des mesures correctives pour empêcher que ceux-ci ne se reproduisent;

g) des documents exposant tous les processus du système de gestion et les processus visant à faire connaître aux membres du personnel leurs rôles et leurs responsabilités à cet égard;

h) des processus permettant de veiller à ce que tous les documents relatifs au système soient à jour, valides et approuvés par le niveau décisionnel compétent;

i) des processus permettant d'effectuer des examens ou des vérifications périodiques du système et d'appliquer des mesures correctives lorsque les examens ou vérifications révèlent des manquements au système de gestion et des domaines susceptibles d'amélioration;

j) des dispositions concernant la coordination des fonctions de gestion et d'exploitation de l'activité projetée, entre le propriétaire de l'installation, les entrepreneurs, l'exploitant et les autres parties, selon le cas;

k) le nom et le titre du poste de la personne qui doit répondre de l'élaboration et de la tenue du système de gestion et de la personne chargée de sa mise en œuvre.

(3) La documentation relative au système de gestion doit être contrôlée et présentée d'une manière logique et systématique pour en faciliter la compréhension et pour assurer l'application efficace du système.

(4) Le système de gestion doit être adapté à l'importance, à la nature et à la complexité des travaux et des activités, ainsi que des dangers et risques connexes.

DEMANDE D'AUTORISATION

6. La demande d'autorisation est accompagnée des documents et renseignements suivants :

a) la description de l'étendue des activités projetées;

b) un plan de mise en œuvre et un calendrier des activités projetées;

c) un plan de sécurité qui répond aux exigences de l'article 8;

d) un plan de protection de l'environnement qui répond aux exigences de l'article 9;

e) des renseignements sur le brûlage de gaz à la torche ou le rejet de gaz dans l'atmosphère qui sont prévus, y compris la (*f*) information on any proposed burning of oil, including the rationale and the estimated quantity of oil proposed to be burned;

(*g*) in the case of a drilling installation, a description of the drilling and well control equipment;

(*h*) in the case of a production installation, a description of the processing facilities and control system;

(*i*) in the case of a production project, a field data acquisition program that allows sufficient pool pressure measurements, fluid samples, cased hole logs and formation flow tests for a comprehensive assessment of the performance of development wells, pool depletion schemes and the field;

(*j*) contingency plans, including emergency response procedures, to mitigate the effects of any reasonably foreseeable event that might compromise safety or environmental protection, which shall

(i) provide for coordination measures with any relevant municipal, provincial, territorial or federal emergency response plan, and

(ii) in an offshore area where oil is reasonably expected to be encountered, identify the scope and frequency of the field practice exercise of oil spill countermeasures; and

(*k*) a description of the decommissioning and abandonment of the site, including methods for restoration of the site after its abandonment.

7. (1) If the application for authorization covers a production installation, the applicant shall also submit to the Board for its approval the flow system, the flow calculation procedure and the flow allocation procedure that will be used to conduct the measurements referred to in Part 7.

(2) The Board shall approve the flow system, the flow calculation procedure and the flow allocation procedure if the applicant demonstrates that the system and procedures facilitate reasonably accurate measurements and allocate, on a pool or zone basis, the production from and injection into individual wells.

8. The safety plan shall set out the procedures, practices, resources, sequence of key safety-related activities and monitoring measures necessary to ensure the safety of the proposed work or activity and shall include

(*a*) a summary of and references to the management system that demonstrate how it will be applied to the proposed work or activity and how the duties set out in these Regulations with regard to safety will be fulfilled;

(*b*) a summary of the studies undertaken to identify hazards and to evaluate safety risks related to the proposed work or activity;

(*c*) a description of the hazards that were identified and the results of the risk evaluation;

(*d*) a summary of the measures to avoid, prevent, reduce and manage safety risks;

(*e*) a list of all structures, facilities, equipment and systems critical to safety and a summary of the system in place for their inspection, testing and maintenance;

raison du brûlage ou du rejet et une estimation du taux de rejet, des quantités de gaz qu'il est prévu de brûler ou de rejeter et de la période de temps au cours de laquelle le brûlage ou le rejet aura lieu;

f) des renseignements sur le brûlage de pétrole prévu, y compris la raison du brûlage et une estimation des quantités qu'il est prévu de brûler;

g) dans le cas d'une installation de forage, la description de l'équipement de forage et de contrôle des puits;

h) dans le cas d'une installation de production, la description du matériel de transformation et du système de contrôle;

i) dans le cas d'un projet de production, un programme d'acquisition des données relatives au champ, élaboré de manière à permettre l'obtention des mesures de la pression du gisement, des échantillons de fluide, des diagraphies en puits tubé et des essais d'écoulement de formation du puits nécessaires à une évaluation complète de la performance des puits d'exploitation, des scénarios d'épuisement du gisement et du champ;

j) des plans d'urgence, y compris des procédures d'intervention d'urgence, en vue de réduire les conséquences de tout événement normalement prévisible qui pourrait compromettre la sécurité ou la protection de l'environnement, lesquels doivent :

(i) prévoir des mesures permettant leur coordination avec tout plan d'intervention d'urgence municipal, provincial, territorial ou fédéral pertinent,

(ii) dans le cas d'une région extracôtière où du pétrole peut vraisemblablement être découvert, préciser l'étendue et la fréquence des exercices d'intervention en cas de rejet de pétrole;

k) une description des procédures de désaffectation et d'abandon du site, y compris les méthodes de rétablissement du site après l'abandon.

7. (1) Si la demande d'autorisation vise une installation de production, le demandeur soumet aussi à l'approbation de l'Office le système d'écoulement et les méthodes de calcul et de répartition du débit qui seront utilisés pour effectuer le mesurage prévu à la partie 7.

(2) L'Office approuve le système d'écoulement et les méthodes de calcul et de répartition du débit si le demandeur établit qu'ils permettent de déterminer de façon suffisamment précise les mesures et répartit, par gisement ou couche, la production et l'injection pour chaque puits.

8. Le plan de sécurité doit prévoir les procédures, les pratiques, les ressources, la séquence des principales activités en matière de sécurité et les mesures de surveillance nécessaires pour assurer la sécurité des activités projetées et doit en outre comporter :

a) un résumé du système de gestion et les renvois à celui-ci qui démontrent sa mise en œuvre pendant le déroulement des activités projetées et comment le système de gestion permettra de se conformer aux obligations prévues par le présent règlement en matière de sécurité;

b) un résumé des études réalisées pour cerner les dangers et évaluer les risques pour la sécurité liés aux activités projetées;

c) la description des dangers cernés et les résultats de l'évaluation des risques;

d) un résumé des mesures pour éviter, prévenir, réduire et contrôler les risques pour la sécurité;

e) une liste des structures, du matériel, de l'équipement et des systèmes qui sont essentiels à la sécurité, ainsi qu'un résumé du (*f*) a description of the organizational structure for the proposed work or activity and the command structure on the installation, which clearly explains

(i) their relationship to each other, and

(ii) the contact information and position of the person accountable for the safety plan and of the person responsible for implementing it;

(*g*) if the possibility of pack sea ice, drifting icebergs or land-fast sea ice exists at the drill or production site, the measures to address the protection of the installation, including systems for ice detection, surveillance, data collection, reporting, forecasting and, if appropriate, ice avoidance or deflection; and

(*h*) a description of the arrangements for monitoring compliance with the plan and for measuring performance in relation to its objectives.

système en place pour veiller à leur inspection, essai et entretien;

f) une description de la structure organisationnelle relative à l'exécution des activités projetées et de la structure de commandement de l'installation, qui indique clairement :

(i) le lien entre les deux structures,

(ii) le titre du poste et les coordonnées de la personne qui répond du plan de sécurité et de la personne chargée de sa mise en œuvre;

g) s'il risque d'y avoir des banquises marines, des icebergs flottants ou des banquises côtières sur les lieux de forage ou de production, les mesures prévues pour assurer la protection de l'installation, y compris les systèmes de détection et de surveillance des glaces, de collecte des données, de signalement et de prévision et, s'il y a lieu, d'évitement ou de déviation des glaces;

h) une description des mécanismes de surveillance nécessaires pour veiller à ce que le plan soit mis en œuvre et pour évaluer le rendement au regard de ses objectifs.

9. The environmental protection plan shall set out the procedures, practices, resources and monitoring necessary to manage hazards to and protect the environment from the proposed work or activity and shall include

(*a*) a summary of and references to the management system that demonstrate how it will be applied to the proposed work or activity and how the duties set out in these Regulations with regard to environmental protection will be fulfilled;

(*b*) a summary of the studies undertaken to identify environmental hazards and to evaluate environmental risks relating to the proposed work or activity;

(*c*) a description of the hazards that were identified and the results of the risk evaluation;

(*d*) a summary of the measures to avoid, prevent, reduce and manage environmental risks;

(*e*) a list of all structures, facilities, equipment and systems critical to environmental protection and a summary of the system in place for their inspection, testing and maintenance;

(*f*) a description of the organizational structure for the proposed work or activity and the command structure on the installation, which clearly explains

(i) their relationship to each other, and

(ii) the contact information and position of the person accountable for the environmental protection plan and the person responsible for implementing it;

(*g*) the procedures for the selection, evaluation and use of chemical substances including process chemicals and drilling fluid ingredients;

(*h*) a description of equipment and procedures for the treatment, handling and disposal of waste material;

(*i*) a description of all discharge streams and limits for any discharge into the natural environment including any waste material;

(*j*) a description of the system for monitoring compliance with the discharge limits identified in paragraph (*i*), including the sampling and analytical program to determine if those discharges are within the specified limits; and

(*k*) a description of the arrangements for monitoring compliance with the plan and for measuring performance in relation to its objectives.

9. Le plan de protection de l'environnement doit prévoir les procédures, les pratiques, les ressources et les mesures de surveillance nécessaires pour gérer les dangers pour l'environnement et protéger celui-ci des activités projetées et doit en outre comporter :

a) un résumé du système de gestion et les renvois à celui-ci qui démontrent sa mise en œuvre pendant le déroulement des activités projetées et comment le système de gestion permettra de se conformer aux obligations prévues par le présent règlement en matière de protection de l'environnement;

b) un résumé des études réalisées pour cerner les dangers pour l'environnement et évaluer les risques pour l'environnement liés aux activités projetées;

c) une description des dangers cernés et les résultats de l'évaluation des risques;

d) un résumé des mesures prévues pour éviter, prévenir, réduire et contrôler les risques pour l'environnement;

e) une liste des structures, du matériel, de l'équipement et des systèmes essentiels à la protection de l'environnement, ainsi qu'un résumé du système en place pour leur inspection, essai et entretien;

f) une description de la structure organisationnelle relative à l'exécution des activités projetées et de la structure de commandement de l'installation, qui indique clairement :

(i) le lien entre les deux structures,

(ii) le titre du poste et les coordonnées de la personne qui répond du plan de protection de l'environnement et de la personne chargée de sa mise en œuvre;

g) les procédures de sélection, d'évaluation et d'utilisation des substances chimiques, y compris les produits chimiques utilisés pour les procédés et les fluides de forage;

h) une description de l'équipement et des procédés de traitement, de manutention et d'élimination des déchets;

i) une description de toutes les voies d'évacuation et des limites relatives à toute évacuation dans le milieu naturel, y compris l'évacuation des déchets;

j) une description du système de contrôle des limites d'évacuation visées à l'alinéa *h*), y compris le programme d'échantillonnage et d'analyse servant à vérifier si les limites sont respectées;

WELL APPROVAL

10. (1) Subject to subsection (2), an operator who intends to drill, re-enter, work over, complete or recomplete a well or suspend or abandon a well or part of a well shall obtain a well approval.

(2) A well approval is not necessary to conduct a wire line, slick line or coiled tubing operation through a Christmas tree located above sea level if

(*a*) the work does not alter the completion interval or is not expected to adversely affect recovery; and

(*b*) the equipment, operating procedures and qualified persons exist to conduct the wire line, slick line or coiled tubing operations as set out in the authorization.

11. If the well approval sought is to drill a well, the application shall contain

(*a*) a comprehensive description of the drilling program; and

(*b*) a well data acquisition program that allows for the collection of sufficient cutting and fluid samples, logs, conventional cores, sidewall cores, pressure measurements and formation flow tests, analyses and surveys to enable a comprehensive geological and reservoir evaluation to be made.

12. The application shall contain

(*a*) if the well approval sought is to re-enter, work over, complete or recomplete a well or suspend or abandon a well or part of it, a detailed description of that well, the proposed work or activity and the rationale for conducting it;

(*b*) if the well approval sought is to complete a well, in addition to the information required under paragraph (*a*), information that demonstrates that section 46 will be complied with; and

(*c*) if the well approval sought is to suspend a well or part of it, in addition to the information required under paragraph (*a*), an indication of the period within which the suspended well or part of it will be abandoned or completed.

13. The Board shall grant the well approval if the operator demonstrates that the work or activity will be conducted safely, without waste and without pollution, in compliance with these Regulations.

SUSPENSION AND REVOCATION OF A WELL APPROVAL

14. (1) The Board may suspend the well approval if

(*a*) the operator fails to comply with the approval and the work or activity cannot be conducted safely, without waste or without pollution;

(*b*) the safety of the work or activity becomes uncertain because

(i) the level of performance of the installation or service equipment, any ancillary equipment or any support craft is demonstrably less than the level of performance indicated in the application, or

k) une description des mesures prises pour contrôler la conformité au plan et en évaluer le rendement au regard de ses objectifs.

APPROBATION RELATIVE AU PUITS

10. (1) Sous réserve du paragraphe (2), l'exploitant qui a l'intention de procéder, à l'égard d'un puits ou d'une partie de puits, à des travaux de forage, de rentrée, de reconditionnement, de complétion, de remise en production, de suspension de l'exploitation ou d'abandon doit avoir reçu l'approbation afférente.

(2) Aucune approbation n'est nécessaire pour exécuter des travaux par câble, par câble lisse ou par tube de production concentrique au moyen d'une tête d'éruption installée au-dessus du niveau de la mer, si les conditions suivantes sont réunies :

a) les travaux exécutés ne modifient pas l'état d'un intervalle de complétion ou ne devraient pas nuire à la récupération;

b) l'équipement, les marches à suivre et les qualifications du personnel effectuant le travail sont conformes à l'autorisation.

11. La demande d'approbation relative à un puits qui vise le forage contient :

a) une description complète du programme de forage;

b) un programme d'acquisition de données relatives au puits élaboré de manière à permettre l'obtention des échantillons de déblais et de fluide, des diagraphies, des carottes classiques, des carottes latérales, des mesures de pression, des essais d'écoulement de formation, des analyses et des levés nécessaires à une évaluation complète de la géologie et du réservoir.

12. La demande d'approbation relative à un puits qui vise les travaux ci-après contient :

a) s'agissant d'une rentrée ou de travaux de reconditionnement, de complétion, de remise en production, de suspension de l'exploitation ou d'abandon visant un puits ou une partie d'un puits, une description détaillée du puits ou de la partie, de l'activité projetée et de son but;

b) s'agissant de la complétion d'un puits, outre les renseignements mentionnés à l'alinéa *a*), des renseignements démontrant que les exigences de l'article 46 seront respectées;

c) s'agissant de la suspension de l'exploitation d'un puits ou d'une partie d'un puits, outre les renseignements mentionnés à l'alinéa *a*), la mention du délai dans lequel le puits ou la partie de puits sera abandonné ou complété.

13. L'Office accorde l'approbation relative au puits si l'exploitant démontre que les activités seront menées en toute sécurité, sans gaspillage ni pollution, conformément au présent règlement.

SUSPENSION ET ANNULATION DE L'APPROBATION RELATIVE À UN PUITS

14. (1) L'Office peut suspendre l'approbation relative au puits dans les cas suivants :

a) l'exploitant omet de se conformer à toute condition de l'approbation et les activités ne peuvent plus être menées en toute sécurité ou sans gaspillage ou pollution;

b) la sécurité des activités ne peut plus être assurée pour l'une ou l'autre des raisons suivantes :

(i) le niveau de rendement de l'installation, de l'équipement de service ou auxiliaire ou d'un véhicule de service est nettement inférieur au niveau précisé dans la demande d'approbation,

(ii) the physical environmental conditions encountered in the area of the activity for which the well approval was granted are more severe than the equipment's operating limits as specified by the manufacturer; or

(*c*) the operator fails to comply with the approvals issued under subsection 7(2), 52(4) or 66(2).

(2) The Board may revoke the well approval if the operator fails to remedy the situation causing the suspension within 120 days after the date of that suspension.

DEVELOPMENT PLANS

15. For the purpose of subsection 5.1(1) of the Act, the well approval relating to a production project is prescribed.

16. For the purpose of paragraph 5.1(3)(*b*) of the Act, Part II of the development plan relating to a proposed development of a pool or field shall contain a resource management plan.

PART 3

OPERATOR'S DUTIES

AVAILABILITY OF DOCUMENTS

17. (1) The operator shall keep a copy of the authorization, the well approval and all other approvals and plans required under these Regulations, the Act and the regulations made under the Act at each installation and shall make them available for examination at the request of any person at each installation.

(2) The operator shall ensure that a copy of all operating manuals and other procedures and documents necessary to execute the work or activity and to operate the installation safely without pollution are readily accessible at each installation.

MANAGEMENT SYSTEM

18. The operator shall ensure compliance with the management system referred to in section 5.

SAFETY AND ENVIRONMENTAL PROTECTION

19. The operator shall take all reasonable precautions to ensure safety and environmental protection, including ensuring that

(*a*) any operation necessary for the safety of persons at an installation or on a support craft has priority, at all times, over any work or activity at that installation or on that support craft;

(*b*) safe work methods are followed during all drilling, well or production operations;

(*c*) there is a shift handover system to effectively communicate any conditions, mechanical or procedural deficiencies or other problems that might have an impact on safety or environmental protection;

(*d*) differences in language or other barriers to effective communication do not jeopardize safety or environmental protection;

(*e*) all persons at an installation, or in transit to or from an installation, receive instruction in and are familiar with safety and evacuation procedures and with their roles and responsibilities in the contingency plans, including emergency response procedures;

(ii) les conditions environnementales existant dans la zone où se déroule l'activité pour laquelle l'approbation a été accordée sont plus difficiles que celles prévues par le fabricant de l'équipement;

c) l'exploitant omet de se conformer à l'approbation délivrée par l'Office aux termes des paragraphes 7(2), 52(4) ou 66(2).

(2) L'Office peut annuler l'approbation si l'exploitant omet de corriger la situation dans les cent vingt jours suivant la suspension.

PLAN DE MISE EN VALEUR

15. L'approbation relative au puits qui vise un projet de production vaut pour l'application du paragraphe 5.1(1) de la Loi.

16. Pour l'application du paragraphe 5.1(3) de la Loi, la seconde partie du projet de plan de mise en valeur relatif à des activités projetées sur un gisement ou un champ doit contenir un plan de gestion des ressources.

PARTIE 3

OBLIGATIONS DE L'EXPLOITANT

DISPONIBILITÉ DES DOCUMENTS

17. (1) L'exploitant conserve à chaque installation une copie de l'autorisation, de l'approbation relative au puits et de toute autre approbation ainsi que de tout plan exigés par le présent règlement et par la Loi et ses règlements, et les met, sur place, à la disposition de quiconque en fait la demande.

(2) L'exploitant veille à ce qu'une copie des manuels d'exploitation et de tout autre procédé ou document nécessaire à la conduite des activités et au fonctionnement sûr et sans pollution de l'installation soit facilement accessible à chaque installation.

SYSTÈME DE GESTION

18. L'exploitant veille au respect du système de gestion prévu à l'article 5.

SÉCURITÉ ET PROTECTION DE L'ENVIRONNEMENT

19. L'exploitant doit prendre toutes les mesures voulues pour assurer la sécurité et la protection de l'environnement, notamment :

a) prendre les dispositions nécessaires pour assurer prioritairement et en tout temps la sécurité des personnes se trouvant dans une installation ou un véhicule de service;

b) adopter des méthodes de travail sûres pendant l'exécution des activités de forage, des travaux relatifs à un puits et des travaux de production;

c) mettre en place un système pour assurer, à chaque changement d'équipe de travail, la communication efficace de tout renseignement relatif aux conditions, aux problèmes mécaniques ou opérationnels ou à d'autres problèmes susceptibles d'influer sur la sécurité des personnes ou sur la protection de l'environnement;

d) veiller à ce que la sécurité ou la protection de l'environnement ne soit pas compromise du fait d'une mauvaise communication due à des obstacles linguistiques ou à d'autres facteurs;

(*f*) any drilling or well operation is conducted in a manner that maintains full control of the well at all times;

(*g*) if there is loss of control of a well at an installation, all other wells at that installation are shut in until the well that is out of control is secured;

(*h*) plans are in place to deal with potential hazards;

(*i*) all equipment required for safety and environmental protection is available and in an operable condition;

(*j*) the inventory of all equipment identified in the safety plan and the environmental protection plan is updated after the completion of any significant modification or repair to any major component of the equipment;

(*k*) the administrative and logistical support that is provided for drilling, well or production operations includes accommodation, transportation, first aid and storage, repair facilities and communication systems suitable for the area of operations;

(*l*) a sufficient number of trained and competent individuals are available to complete the authorized work or activities and to carry out any work or activity safely and without pollution; and

(*m*) any operational procedure that is a hazard to safety or the environment is corrected and all affected persons are informed of the alteration.

20. (1) No person shall tamper with, activate without cause, or misuse any safety or environmental protection equipment.

(2) A passenger on a helicopter, supply vessel or any other support craft engaged in a drilling program or production project shall comply with all applicable safety instructions.

21. (1) No person shall smoke on an installation except in those areas set aside by the operator for that use.

(2) The operator shall ensure compliance with subsection (1).

STORING AND HANDLING OF CONSUMABLES

22. The operator shall ensure that fuel, potable water, spill containment products, safety-related chemicals, drilling fluids, cement and other consumables are

(*a*) readily available and stored on an installation in quantities sufficient for any normal and reasonably foreseeable emergency condition; and

(*b*) stored and handled in a manner that minimizes their deterioration, ensures safety and prevents pollution.

e) s'assurer que toutes les personnes se trouvant dans une installation ou qui y transitent sont informées des consignes de sécurité et des procédures d'évacuation, ainsi que des rôles et des responsabilités qui leur incombent aux termes des plans d'urgence, y compris des procédures d'intervention d'urgence;

f) faire en sorte que toutes les activités de forage ou tous les travaux relatifs à un puits soient effectués de manière à ce que le puits soit entièrement contrôlé en tout temps;

g) s'assurer que, en cas de perte de contrôle d'un puits à une installation, les obturateurs de tous les autres puits de l'installation sont fermés, jusqu'à ce que le puits ne présente plus de danger;

h) prévoir des dispositions pour corriger toute situation comportant des risques potentiels;

i) vérifier que tout l'équipement nécessaire à la sécurité et à la protection de l'environnement est en bon état et utilisable au besoin;

j) s'assurer que la liste de tout l'équipement mentionné dans le plan de sécurité et de protection de l'environnement est mise à jour après toute modification ou réparation majeure à une pièce d'équipement importante;

k) faire en sorte que le soutien administratif et logistique prévu pour les activités de forage, les travaux relatifs à un puits et les travaux de production comprenne la fourniture de logement, de services de transport, d'aménagements de premiers soins, d'aménagements d'entreposage, d'ateliers de réparation et de systèmes de communication adaptés à la région;

l) veiller à ce que des personnes formées et compétentes soient en nombre suffisant pour mener à terme les activités visées par l'autorisation en toute sécurité et sans causer de pollution;

m) corriger toute méthode de travail présentant un risque potentiel pour la sécurité ou l'environnement et en aviser les personnes concernées.

20. (1) Il est interdit d'altérer l'équipement de sécurité ou de protection de l'environnement, de le faire fonctionner sans motif ni d'en faire un mauvais usage.

(2) Tout passager d'un hélicoptère, d'un navire de ravitaillement ou de tout autre véhicule de service participant à un programme de forage ou à un projet de production doit respecter les consignes de sécurité applicables.

21. (1) Il est interdit de fumer dans une installation, sauf aux endroits désignés à cette fin par l'exploitant.

(2) L'exploitant veille au respect du paragraphe (1).

ENTREPOSAGE ET MANUTENTION DES PRODUITS CONSOMPTIBLES

22. L'exploitant veille à ce que le carburant, l'eau potable, les produits de confinement des rejets, les substances chimiques liées à la sécurité, les fluides de forage, le ciment et les autres produits consomptibles soient :

a) facilement accessibles et entreposés à l'installation en quantité suffisante pour répondre aux besoins dans des conditions normales et dans toute autre situation d'urgence normalement prévisible;

b) entreposés et manutentionnés de manière à limiter leur détérioration, à garantir la sécurité et à prévenir toute pollution.

HANDLING OF CHEMICAL SUBSTANCES, WASTE MATERIAL AND OIL

23. The operator shall ensure that all chemical substances, including process fluids and diesel fuel, waste material, drilling fluid and drill cuttings generated at an installation, are handled in a way that does not create a hazard to safety or the environment.

CESSATION OF A WORK OR ACTIVITY

24. (1) The operator shall ensure that any work or activity ceases without delay if that work or activity

(*a*) endangers or is likely to endanger the safety of persons;

(*b*) endangers or is likely to endanger the safety or integrity of the well or the installation; or

(*c*) causes or is likely to cause pollution.

(2) If the work or activity ceases, the operator shall ensure that it does not resume until it can do so safely and without pollution.

PART 4

EQUIPMENT AND OPERATIONS

WELLS, INSTALLATIONS, EQUIPMENT, FACILITIES AND SUPPORT CRAFT

25. The operator shall ensure that

(*a*) all wells, installations, equipment and facilities are designed, constructed, tested, maintained and operated to prevent incidents and waste under the maximum load conditions that may be reasonably anticipated during any operation;

(*b*) a comprehensive inspection that includes a non-destructive examination of critical joints and structural members of an installation and any critical drilling or production equipment is made at an interval to ensure continued safe operation of the installation or equipment and in any case, at least once in every five-year period; and

(*c*) records of maintenance, tests and inspections are kept.

26. The operator shall ensure that

(*a*) the components of an installation and well tubulars, Christmas trees and wellheads are operated in accordance with good engineering practices; and

(*b*) any part of an installation that may be exposed to a sour environment is designed, constructed and maintained to operate safely in that environment.

27. (1) The operator shall ensure that any defect in the installation, equipment, facilities and support craft that may be a hazard to safety or the environment is rectified without delay.

(2) If it is not possible to rectify the defect without delay, the operator shall ensure that it is rectified as soon as the circumstances permit and that mitigation measures are put in place to minimize the hazards while the defect is being rectified.

MANUTENTION DES SUBSTANCES CHIMIQUES, DES DÉCHETS ET DU PÉTROLE

23. L'exploitant veille à ce que les substances chimiques, y compris les fluides de traitement et le diesel, les déchets, le fluide et les déblais de forage produits à l'installation soient manipulés de manière à ne pas poser de risque pour la sécurité ou l'environnement.

CESSATION DES ACTIVITÉS

24. (1) L'exploitant veille à ce que les activités cessent sans délai si elles :

a) menacent ou sont susceptibles de menacer la sécurité des personnes;

b) menacent ou sont susceptibles de menacer la sécurité ou l'intégrité du puits ou de l'installation;

c) causent ou sont susceptibles de causer de la pollution.

(2) En cas d'interruption des activités, l'exploitant veille à ce qu'elles ne soient reprises que si la situation ayant mené à la cessation est rétablie.

PARTIE 4

ÉQUIPEMENT ET ACTIVITÉS

PUITS, INSTALLATIONS, ÉQUIPEMENT, MATÉRIEL ET VÉHICULES DE SERVICE

25. L'exploitant veille au respect des exigences suivantes :

a) tout puits, toute installation, tout équipement et tout matériel sont conçus, construits, mis à l'essai, entretenus et exploités de manière à prévenir les incidents et le gaspillage dans des conditions de charge maximale normalement prévisibles pendant les activités;

b) une inspection complète, comportant notamment des examens non destructifs des raccords critiques et des éléments structuraux de toute l'installation et de tout équipement critique de forage ou de production, est effectuée à un intervalle permettant de garantir la sécurité de fonctionnement de l'installation ou de l'équipement, et, dans tous les cas, au moins une fois tous les cinq ans;

c) des registres de l'entretien, des essais et des inspections sont conservés.

26. L'exploitant veille au respect des exigences suivantes :

a) les éléments de l'installation, le matériel tubulaire des puits, les têtes d'éruption et têtes de puits sont utilisés conformément aux règles de l'art en matière d'ingénierie;

b) toute partie de l'installation susceptible d'être exposée à un environnement acide est conçue, construite et entretenue pour fonctionner en toute sécurité dans un tel environnement.

27. (1) L'exploitant veille à ce que toute défaillance de l'installation, de l'équipement, du matériel ou d'un véhicule de service pouvant présenter un risque pour la sécurité ou l'environnement soit corrigée sans délai.

(2) En cas de retard inévitable, l'exploitant veille à ce que toute défaillance soit corrigée aussitôt que les circonstances le permettent et que des mesures d'atténuation soient prises entre-temps pour réduire les risques au minimum.

DRILLING FLUID SYSTEM

28. The operator shall ensure that

(*a*) the drilling fluid system and associated monitoring equipment is designed, installed, operated and maintained to provide an effective barrier against formation pressure, to allow for proper well evaluation, to ensure safe drilling operations and to prevent pollution; and

(*b*) the indicators and alarms associated with the monitoring equipment are strategically located on the drilling rig to alert onsite personnel.

MARINE RISER

29. (1) The operator shall ensure that every marine riser is capable of

(*a*) furnishing access to the well;

(*b*) isolating the well-bore from the sea;

(*c*) withstanding the differential pressure of the drilling fluid relative to the sea;

(*d*) withstanding the physical forces anticipated in the drilling program; and

(*e*) permitting the drilling fluid to be returned to the installation.

(2) The operator shall ensure that every marine riser is supported in a manner that effectively compensates for the forces caused by the motion of the installation.

DRILLING PRACTICES

30. The operator shall ensure that adequate equipment, procedures and personnel are in place to recognize and control normal and abnormal pressures, to allow for safe, controlled drilling operations and to prevent pollution.

REFERENCE FOR WELL DEPTHS

31. The operator shall ensure that any depth in a well is measured from a single reference point, which is either the kelly bushing or the rotary table of the drilling rig.

DIRECTIONAL AND DEVIATION SURVEYS

32. The operator shall ensure that

(*a*) directional and deviation surveys are taken at intervals that allow the position of the well-bore to be determined accurately; and

(*b*) except in the case of a relief well, a well is drilled in a manner that does not intersect an existing well.

FORMATION LEAK-OFF TEST

33. The operator shall ensure that

(*a*) a formation leak-off test or a formation integrity test is conducted before drilling more than 10 m below the shoe of any casing other than the conductor casing;

(*b*) the formation leak-off test or the formation integrity test is conducted to a pressure that allows for safe drilling to the next planned casing depth; and

CIRCUIT DU FLUIDE DE FORAGE

28. L'exploitant veille au respect des exigences suivantes :

a) le circuit du fluide de forage et l'équipement de contrôle connexe sont conçus, installés, exploités et entretenus de manière à constituer une barrière efficace contre la pression de formation, à permettre une évaluation adéquate du puits, à assurer le déroulement sûr des activités de forage et à prévenir la pollution;

b) les indicateurs et les dispositifs d'alarme liés à l'équipement de contrôle sont installés à des endroits stratégiques sur l'appareil de forage, de manière à alerter le personnel qui s'y trouve.

TUBE PROLONGATEUR

29. (1) L'exploitant veille à ce que le tube prolongateur puisse :

a) fournir un accès au puits;

b) isoler le trou de sonde de la mer;

c) résister à la différence de pression entre le fluide de forage et la mer;

d) résister aux forces physiques prévues pendant le programme de forage;

e) permettre au fluide de forage de retourner à l'installation.

(2) L'exploitant veille à ce que le tube prolongateur soit supporté de manière à compenser efficacement les forces résultant du mouvement de l'installation.

PRATIQUES DE FORAGE

30. L'exploitant veille à ce que du personnel, des procédures et de l'équipement adéquats soient en place pour constater et contrôler les pressions normales et anormales, pour assurer le déroulement sûr et contrôlé des activités de forage et pour prévenir la pollution.

RÉFÉRENCE POUR LA PROFONDEUR DU PUITS

31. L'exploitant veille à ce que toute mesure de la profondeur d'un puits soit prise à partir d'un point de référence unique, qui est soit la table de rotation, soit la fourrure d'entraînement de l'appareil de forage.

MESURES DE DÉVIATION ET DE DIRECTION

32. L'exploitant veille au respect des exigences suivantes :

a) les mesures de déviation et de direction sont effectuées à des intervalles qui permettent de situer correctement le trou de sonde;

b) le puits est foré de manière à ne jamais couper un puits existant, sauf s'il s'agit d'un puits de secours.

TEST DE PRESSION DE FRACTURATION

33. L'exploitant veille au respect des exigences suivantes :

a) un test de pression de fracturation ou un essai d'intégrité de la formation est effectué avant de forer à une profondeur de plus de 10 m au-dessous du sabot de tout tubage autre que le tubage initial;

b) le test ou l'essai est effectué à une pression qui permet d'assurer la sécurité du forage jusqu'à la prochaine profondeur de colonne prévue;

(*c*) a record is retained of each formation leak-off test and the results included in the daily drilling report referred to in paragraph 83(*a*) and in the well history report referred to in section 88.

FORMATION FLOW AND WELL TESTING EQUIPMENT

34. (1) The operator shall ensure that

(*a*) the equipment used in a formation flow test is designed to safely control well pressure, properly evaluate the formation and prevent pollution;

(*b*) the rated working pressure of formation flow test equipment upstream of and including the well testing manifold exceeds the maximum anticipated shut-in pressure; and

(*c*) the equipment downstream of the well testing manifold is sufficiently protected against overpressure.

(2) The operator of an offshore well or a well in a sour environment shall ensure that the formation flow test equipment includes a down-hole safety valve that permits closure of the test string above the packer.

(3) The operator shall ensure that any formation flow test equipment used in testing an offshore well that is drilled with a floating drilling unit has a subsea test tree that includes

(*a*) a valve that may be operated from the surface and automatically closes when required to prevent uncontrolled well flow; and

(*b*) a release system that permits the test string to be hydraulically or mechanically disconnected within or below the blowout preventers.

WELL CONTROL

35. The operator shall ensure that adequate procedures, materials and equipment are in place and utilized to minimize the risk of loss of well control in the event of lost circulation.

36. (1) The operator shall ensure that, during all well operations, reliably operating well control equipment is installed to control kicks, prevent blow-outs and safely carry out all well activities and operations, including drilling, completion and workover operations.

(2) After setting the surface casing, the operator shall ensure that at least two independent and tested well barriers are in place during all well operations.

(3) If a barrier fails, the operator shall ensure that no other activities, other than those intended to restore or replace the barrier, take place in the well.

(4) The operator shall ensure that, during drilling, except when drilling under-balanced, one of the two barriers to be maintained is the drilling fluid column.

37. The operator shall ensure that pressure control equipment associated with drilling, coil tubing, slick line and wire line operations is pressure-tested on installation and as often as necessary to ensure its continued safe operation.

c) un registre de chaque test de pression de fracturation est conservé et les résultats sont consignés dans le rapport journalier de forage visé à l'alinéa 83*a*) et dans le rapport final du puits visé à l'article 88.

ÉQUIPEMENT POUR LES ESSAIS D'ÉCOULEMENT DE FORMATION ET LES ESSAIS D'UN PUITS

34. (1) L'exploitant veille au respect des exigences suivantes :

a) l'équipement utilisé pour les essais d'écoulement de formation est conçu de façon à contrôler en toute sécurité la pression du puits, à évaluer correctement la formation et à prévenir la pollution;

b) la pression nominale de marche de tout équipement utilisé pour les essais d'écoulement de formation, au niveau du collecteur d'essai du puits et en amont de celui-ci est supérieure à la pression statique maximale prévue;

c) l'équipement en aval du collecteur d'essai du puits est suffisamment protégé contre la surpression.

(2) L'exploitant d'un puits extracôtier ou d'un puits situé dans un environnement acide veille à ce que l'équipement utilisé pour les essais d'écoulement comprenne une vanne de sécurité de fond qui permet la fermeture du train de tiges d'essai au-dessus de la garniture d'étanchéité.

(3) L'exploitant veille à ce que l'équipement utilisé pour les essais d'écoulement de formation dans un puits extracôtier foré à l'aide d'une unité de forage flottante comporte une tête de puits d'essai sous-marine munie :

a) d'une soupape qui peut être manœuvrée de la surface et se ferme automatiquement au besoin pour empêcher un écoulement incontrôlé du puits;

b) d'un système de libération qui permet au train de tiges d'essai d'être débranché de façon mécanique ou hydraulique à l'intérieur ou au-dessous des blocs d'obturation.

CONTRÔLE DES PUITS

35. L'exploitant veille à ce que des procédures, des matériaux et de l'équipement adéquats soient en place et utilisés pour réduire le risque de perte de contrôle du puits en cas de perte de circulation.

36. (1) L'exploitant veille à ce que, au cours des travaux relatifs à un puits, de l'équipement fiable de contrôle du puits soit en place pour contrôler les venues, prévenir les éruptions et exécuter en toute sécurité les activités et les travaux relatifs au puits, y compris le forage, la complétion et le reconditionnement.

(2) L'exploitant veille à ce que, après l'installation du tubage de surface, au moins deux barrières indépendantes et éprouvées soient en place, et ce, pendant tous les travaux relatifs au puits.

(3) L'exploitant veille à ce que, en cas de défaillance d'une barrière, seules les activités destinées à sa réparation ou à son remplacement soient menées dans le puits.

(4) L'exploitant veille à ce que, durant le forage, l'une des deux barrières soit la colonne de fluide de forage, sauf si le forage est effectué en sous-équilibre.

37. L'exploitant veille à ce que l'équipement de contrôle de pression utilisé pour les activités de forage et les opérations par tube de production concentrique et par câble lisse ou autre soit soumis à une épreuve sous pression au moment de son installation, et par la suite, aussi souvent que cela est nécessaire pour en garantir la sécurité de fonctionnement.

38. If the well control is lost or if safety, environmental protection or resource conservation is at risk, the operator shall ensure that any action necessary to rectify the situation is taken without delay, despite any condition to the contrary in the well approval.

38. Advenant la perte de contrôle du puits ou si la sécurité, la protection de l'environnement ou la conservation des ressources est menacée, l'exploitant veille à ce que les mesures correctives nécessaires soient prises sans délai, malgré toute disposition contraire prévue par l'approbation relative au puits.

Casing and Cementing

39. The operator shall ensure that the well and casing are designed so that

(*a*) the well can be drilled safely, the targeted formations evaluated and waste prevented;

(*b*) the anticipated conditions, forces and stresses that may be placed upon them are withstood; and

(*c*) the integrity of gas hydrate and permafrost zones — and, in the case of an onshore well, potable water zones — is protected.

40. The operator shall ensure that the well and casing are installed at a depth that provides for adequate kick tolerances and well control operations that provide for safe, constant bottom hole pressure.

41. The operator shall ensure that cement slurry is designed and installed so that

(*a*) the movement of formation fluids in the casing annuli is prevented and, where required for safety, resource evaluation or prevention of waste, the isolation of the oil, gas and water zones is ensured;

(*b*) support for the casing is provided;

(*c*) corrosion of the casing over the cemented interval is retarded; and

(*d*) the integrity of gas hydrate and permafrost zones — and, in the case of an onshore well, potable water zones — is protected.

Tubage et cimentation

39. L'exploitant veille à ce que le puits et le tubage soient conçus de façon à :

a) garantir la sécurité des activités de forage, permettre l'évaluation des formations visées et prévenir le gaspillage;

b) pouvoir résister aux conditions, forces et contraintes éventuelles;

c) protéger l'intégrité des couches d'hydrates de gaz et de pergélisol et, dans le cas d'un puits terrestre, des couches d'eau potable.

40. L'exploitant veille à ce que le puits et le tubage se situent à une profondeur qui assure une résistance suffisante aux venues et permet de mener les activités de contrôle de la pression du fond du puits de manière constante et sûre.

41. L'exploitant veille à ce que le laitier de ciment soit conçu et installé de façon à :

a) prévenir le déplacement des fluides de formation dans le tubage annulaire et, lorsque la sécurité, l'évaluation des ressources ou la prévention du gaspillage l'exigent, s'assurer que les couches de pétrole, de gaz et d'eau sont isolées les unes des autres;

b) fournir un support au tubage;

c) retarder la corrosion du tubage se trouvant au-dessus de l'intervalle cimenté;

d) protéger l'intégrité des couches d'hydrates de gaz et de pergélisol et, dans le cas d'un puits terrestre, des couches d'eau potable.

Waiting on Cement Time

42. After the cementing of any casing or casing liner and before drilling out the casing shoe, the operator shall ensure that the cement has reached the minimum compressive strength sufficient to support the casing and provide zonal isolation.

Prise du ciment

42. L'exploitant veille à ce que, après la cimentation d'un tubage — notamment d'un tubage partiel — et avant le reforage du sabot de tubage, le ciment ait atteint une résistance en compression minimale suffisante pour supporter le tubage et garantir l'isolement des couches.

Casing Pressure Testing

43. After installing and cementing the casing and before drilling out the casing shoe, the operator shall ensure that the casing is pressure-tested to the value required to confirm its integrity for maximum anticipated operating pressure.

Épreuve sous pression du tubage

43. Après l'installation et la cimentation d'un tubage et avant le reforage du sabot de tubage, l'exploitant veille à ce que le tubage soit soumis à une épreuve sous pression à une valeur qui permet de confirmer son intégrité à la pression d'utilisation maximale prévue.

Production Tubing

44. The operator shall ensure that the production tubing used in a well is designed to withstand the maximum conditions, forces and stresses that may be placed on it and to maximize recovery from the pool.

Tube de production

44. L'exploitant veille à ce que le tube de production utilisé dans un puits soit conçu de manière à résister aux conditions, forces et contraintes maximales qui pourraient s'y appliquer et à maximiser la récupération du gisement.

Monitoring and Control of Process Operations

45. The operator shall ensure that

(*a*) operations such as processing, transportation, storage, re-injection and handling of oil and gas on the installation are effectively monitored to prevent incidents and waste;

(*b*) all alarm, safety, monitoring, warning and control systems associated with those operations are managed to prevent incidents and waste; and

(*c*) all appropriate persons are informed of the applicable alarm, safety, monitoring, warning or control systems associated with those operations that are taken out of service, and when those systems are returned to service.

Well Completion

46. (1) An operator that completes a well shall ensure that

(*a*) it is completed in a safe manner and allows for maximum recovery;

(*b*) except in the case of commingled production, each completion interval is isolated from any other porous or permeable interval penetrated by the well;

(*c*) the testing and production of any completion interval are conducted safely and do not cause waste or pollution;

(*d*) if applicable, sand production is controlled and does not create a safety hazard or cause waste;

(*e*) each packer is set as close as practical to the top of the completion interval and that the pressure testing of the packer to a differential pressure is greater than the maximum differential pressure anticipated under the production or injection conditions;

(*f*) if practical, any mechanical well condition that may have an adverse effect on production of oil and gas from, or the injection of fluids into, the well is corrected;

(*g*) the injection or production profile of the well is improved, or the completion interval of the well is changed, if it is necessary to do so to prevent waste;

(*h*) if different pressure and inflow characteristics of two or more pools might adversely affect the recovery from any of those pools, the well is operated as a single pool well or as a segregated multi-pool well;

(*i*) after initial completion, all barriers are tested to the maximum pressure to which they are likely to be subjected; and

(*j*) following any workover, any affected barriers are pressure-tested.

(2) The operator of a segregated multi-pool well shall ensure that

(*a*) after the well is completed, segregation has been established within and outside the well casing and is confirmed; and

(*b*) if there is reason to doubt that segregation is being maintained, a segregation test is conducted within a reasonable time frame.

Subsurface Safety Valve

47. (1) The operator of an offshore development well capable of flow shall ensure that the well is equipped with a fail-safe

Surveillance et contrôle des opérations de traitement

45. L'exploitant veille au respect des exigences suivantes :

a) les opérations telles que le traitement, le transport, le stockage, la réinjection et la manutention du pétrole et du gaz à l'installation sont surveillés efficacement de manière à prévenir tout incident et tout gaspillage;

b) tous les systèmes d'alarme, de sécurité, de surveillance, d'avertissement et de contrôle liés à ces opérations sont gérés de manière à prévenir tout incident et tout gaspillage;

c) les personnes compétentes sont informées de la mise hors service ou de la remise en service de ces systèmes.

Complétion d'un puits

46. (1) L'exploitant qui complète un puits veille en outre au respect des exigences suivantes :

a) le puits est complété d'une manière sûre et qui permet une récupération maximale;

b) chaque intervalle de complétion est isolé de tout autre intervalle perméable ou poreux traversé par le puits, sauf dans le cas de production mélangée;

c) l'essai et l'exploitation de tout intervalle de complétion sont effectués en toute sécurité, sans gaspillage ni pollution;

d) le cas échéant, la production de sable est contrôlée, ne pose aucun risque pour la sécurité et ne produit pas de gaspillage;

e) toute garniture d'étanchéité est installée le plus près possible du niveau supérieur de l'intervalle de complétion et mis à l'essai à une pression différentielle supérieure à la pression différentielle maximale prévisible dans des conditions de production ou d'injection;

f) dans la mesure du possible, tout problème d'ordre mécanique du puits pouvant nuire à l'injection de fluides ou à la production de pétrole et de gaz est corrigé;

g) le profil d'injection ou de production du puits est amélioré ou l'intervalle de complétion est modifié, si cela est nécessaire pour prévenir le gaspillage;

h) le puits est exploité soit comme un puits à gisement simple soit comme un puits à gisements multiples séparés, si la différence entre les caractéristiques de pression et d'écoulement de plusieurs gisements peut nuire à la récupération à partir d'un des gisements;

i) après la complétion initiale, toutes les barrières sont soumises à la pression maximale à laquelle elles sont susceptibles d'être exposées;

j) après tout reconditionnement, toutes les barrières exposées sont soumises à une épreuve de pression.

(2) L'exploitant d'un puits à gisements multiples séparés veille au respect des exigences suivantes :

a) à la fin des travaux de complétion, l'étanchéité à l'intérieur comme à l'extérieur du tubage est confirmée;

b) s'il y a des motifs de douter de l'étanchéité, un essai de séparation est effectué dans un délai raisonnable.

Vannes de sécurité de subsurface

47. (1) L'exploitant d'un puits d'exploitation extracôtier qui est éruptif veille à ce que le puits soit muni d'une vanne de sécurité subsurface safety valve that is designed, installed, operated and tested to prevent uncontrolled well flow when it is activated.

(2) If a development well is located in a zone where permafrost is present in unconsolidated sediments, the operator shall ensure that a subsurface safety valve is installed in the tubing below the base of the permafrost.

WELLHEAD AND CHRISTMAS TREE EQUIPMENT

48. The operator shall ensure that the wellhead and Christmas tree equipment, including valves, are designed to operate safely and efficiently under the maximum load conditions anticipated during the life of the well.

PART 5

EVALUATION OF WELLS, POOLS AND FIELDS

GENERAL

49. The operator shall ensure that the well data acquisition program and the field data acquisition program are implemented in accordance with good oilfield practices.

50. (1) If part of the well or field data acquisition program cannot be implemented, the operator shall ensure that

(*a*) a conservation officer is notified as soon as the circumstances permit; and

(*b*) the procedures to otherwise achieve the goals of the program are submitted to the Board for approval.

(2) If the operator can demonstrate that those procedures can achieve the goals of the well or field data acquisition program or are all that can be reasonably expected in the circumstances, the Board shall approve them.

TESTING AND SAMPLING OF FORMATIONS

51. The operator shall ensure that every formation in a well is tested and sampled to obtain reservoir pressure data and fluid samples from the formation, if there is an indication that the data or samples would contribute substantially to the geological and reservoir evaluation.

FORMATION FLOW TESTING

52. (1) The operator shall ensure that

(*a*) no development well is put into production unless the Board has approved a formation flow test in respect of the development well; and

(*b*) if a development well is subjected to a well operation that might change its deliverability, productivity or injectivity, a formation flow test is conducted within a reasonable time frame after the well operation is ended to determine the effects of that operation on the well's deliverability, productivity or injectivity.

(2) The operator may conduct a formation flow test on a well drilled on a geological feature if, before conducting that test, the operator

(*a*) submits to the Board a detailed testing program; and

(*b*) obtains the Board's approval to conduct the test.

de subsurface à sûreté intégrée conçue, installée, mise en service et mise à l'épreuve de manière à empêcher tout écoulement incontrôlé du puits lorsqu'elle est activée.

(2) Si un puits d'exploitation est situé dans une zone de pergélisol formé de sédiments non consolidés, l'exploitant veille à ce qu'une vanne de sécurité de subsurface soit installée dans le tube de production sous la base du pergélisol.

TÊTES DE PUITS ET TÊTES D'ÉRUPTION

48. L'exploitant veille à ce que la tête de puits et la tête d'éruption, y compris les vannes, soient conçues de manière à fonctionner efficacement et en toute sécurité dans des conditions de charge maximale prévisibles pendant la durée de vie du puits.

PARTIE 5

ÉVALUATION DES PUITS, GISEMENTS ET CHAMPS

DISPOSITIONS GÉNÉRALES

49. L'exploitant veille à ce que les programmes d'acquisition des données relatives aux puits et aux champs soient appliqués selon les règles de l'art en matière d'exploitation pétrolière.

50. (1) Si un tel programme ne peut être appliqué en totalité, l'exploitant veille au respect des exigences suivantes :

a) un agent du contrôle de l'exploitation en est avisé aussitôt que les circonstances le permettent;

b) les mesures prévues pour atteindre autrement les objectifs du programme sont soumises à l'approbation de l'Office.

(2) L'Office approuve les mesures prévues à l'alinéa (1)*b*) si l'exploitant démontre qu'elles permettent d'atteindre les objectifs du programme d'acquisition des données relatives au puits ou au champ ou qu'elles sont les seules qui peuvent raisonnablement être prises dans les circonstances.

MISE À L'ESSAI ET ÉCHANTILLONNAGE DES FORMATIONS

51. S'il y a lieu de croire que des données sur la pression des réservoirs ou des échantillons de fluide contribueraient sensiblement à l'évaluation du réservoir et de la géologie des lieux, l'exploitant veille à ce que toute formation dans un puits soit mise à l'essai et échantillonnée de manière à obtenir ces données ou échantillons.

ESSAIS D'ÉCOULEMENT DE FORMATION

52. (1) L'exploitant veille au respect des exigences suivantes :

a) aucun puits d'exploitation n'est mis en production sans que l'Office n'en n'ait approuvé l'essai d'écoulement de formation;

b) lorsqu'un puits d'exploitation fait l'objet de travaux qui pourraient en modifier la capacité de débit, la productivité ou l'injectivité, il est soumis, dans un délai raisonnable après la fin des travaux, à un essai d'écoulement de formation visant à déterminer les effets des travaux sur sa capacité de débit, sa productivité ou son injectivité.

(2) L'exploitant peut effectuer un essai d'écoulement de formation dans un puits foré dans une structure géologique si, au préalable :

a) il remet à l'Office un programme d'essai détaillé;

b) il obtient l'approbation de l'Office pour effectuer cet essai.

(3) The Board may require that the operator conduct a formation flow test on a well drilled on a geological feature, other than the first well, if there is an indication that the test would contribute substantially to the geological and reservoir evaluation.

(4) The Board shall approve a formation flow test if the operator demonstrates that the test will be conducted safely, without pollution and in accordance with good oilfield practices and that the test will enable the operator to

(*a*) obtain data on the deliverability or productivity of the well;

(*b*) establish the characteristics of the reservoir; and

(*c*) obtain representative samples of the formation fluids.

SUBMISSION OF SAMPLES AND DATA

53. The operator shall ensure that all cutting samples, fluid samples and cores collected as part of the well and field data acquisition programs are

(*a*) transported and stored in a manner that prevents any loss or deterioration;

(*b*) delivered to the Board within 60 days after the rig release date unless analyses are ongoing, in which case those samples and cores, or the remaining parts, are to be delivered on completion of the analyses; and

(*c*) stored in durable containers properly labelled for identification.

54. The operator shall ensure that after any samples necessary for analysis or for research or academic studies have been removed from a conventional core, the remaining core, or a longitudinal slab that is not less than one half of the cross-sectional area of that core, is submitted to the Board.

55. Before disposing of cutting samples, fluid samples, cores or evaluation data under these Regulations, the operator shall ensure that the Board is notified in writing and is given an opportunity to request delivery of the samples, cores or data.

PART 6

WELL TERMINATION

SUSPENSION OR ABANDONMENT

56. The operator shall ensure that every well that is suspended or abandoned can be readily located and left in a condition that

(*a*) provides for isolation of all oil or gas bearing zones and discrete pressure zones; and, in the case of an onshore well, potable water zones; and

(*b*) prevents any formation fluid from flowing through or escaping from the well-bore.

57. The operator of a suspended well shall ensure that the well is monitored and inspected to maintain its continued integrity and to prevent pollution.

(3) L'Office peut exiger de l'exploitant qu'il effectue un essai d'écoulement de formation dans un puits foré dans une structure géologique, autre que le premier puits, s'il y a lieu de croire que cet essai contribuerait sensiblement à l'évaluation du réservoir et de la géologie des lieux.

(4) L'Office approuve l'essai d'écoulement de formation si l'exploitant démontre que celui-ci sera effectué en toute sécurité, sans causer de pollution et conformément aux règles de l'art en matière d'exploitation pétrolière et lui permettra à la fois :

a) d'obtenir des données sur la capacité de débit ou la productivité du puits;

b) d'établir les caractéristiques du réservoir;

c) d'obtenir des échantillons représentatifs des liquides de formation.

EXPÉDITION DES ÉCHANTILLONS ET DES DONNÉES

53. L'exploitant veille à ce que les échantillons de déblais de forage ou de fluides et les carottes recueillis dans le cadre des programmes d'acquisition des données relatives aux puits et aux champs soient :

a) transportés et entreposés de manière à prévenir les pertes ou détériorations;

b) expédiés à l'Office dans les soixante jours suivant la date de libération de l'appareil de forage, sauf s'ils sont en cours d'analyse, auquel cas ils sont expédiés, ou ce qu'il en reste est expédié, après l'analyse;

c) emballés dans des contenants durables et correctement étiquetés.

54. Lorsque les échantillons nécessaires à des analyses, à des recherches ou à des études universitaires ont été prélevés d'une carotte classique, l'exploitant veille à ce que le reste de la carotte ou une tranche prise dans le sens longitudinal et correspondant à au moins la moitié de la section transversale de la carotte soit remis à l'Office.

55. L'exploitant veille à ce que, avant l'élimination de tout échantillon de déblais de forage ou de fluides, de carottes ou de données d'évaluation aux termes du présent règlement, l'Office en soit avisé par écrit et à ce qu'on lui offre la possibilité d'en demander livraison.

PARTIE 6

CESSATION DE L'EXPLOITATION D'UN PUITS

SUSPENSION ET ABANDON

56. L'exploitant veille à ce que tout puits abandonné ou dont l'exploitation est suspendue soit facilement localisable et laissé dans un état tel :

a) qu'il assure l'isolement de toute couche renfermant du pétrole ou du gaz, toute couche de pression distincte et, dans le cas d'un puits terrestre, de toute couche d'eau potable;

b) qu'il empêche l'écoulement ou le rejet de fluides de formation du trou de sonde.

57. L'exploitant d'un puits dont l'exploitation est suspendue veille à ce que le puits soit surveillé et inspecté pour en préserver l'intégrité et prévenir la pollution.

58. The operator shall ensure that, on the abandonment of any offshore well, the seafloor is cleared of any material or equipment that might interfere with other commercial uses of the sea.

58. Lorsqu'un puits extracôtier est abandonné, l'exploitant veille à ce que le fond marin soit débarrassé de tout matériel ou équipement qui pourrait nuire aux autres utilisations commerciales de la mer.

INSTALLATION REMOVAL

59. No operator shall remove or cause to have removed a drilling installation from a well drilled under these Regulations unless the well has been terminated in accordance with these Regulations.

DÉPLACEMENT D'UNE INSTALLATION

59. Il est interdit à l'exploitant de retirer ou de faire retirer une installation de forage d'un puits, en vertu du présent règlement, à moins que l'exploitation du puits n'ait cessé conformément au présent règlement.

PART 7

MEASUREMENTS

FLOW AND VOLUME

60. (1) Unless otherwise included in the approval issued under subsection 7(2), the operator shall ensure that the rate of flow and the volume of the following are measured and recorded:

(*a*) the fluid that is produced from each well;

(*b*) the fluid that is injected into each well;

(*c*) any produced fluid that enters, leaves, is used or is flared, vented, burned or otherwise disposed of on an installation, including any battery room, treatment facility or processing plant; and

(*d*) any air or materials injected for the purposes of disposal, storage or cycling, including drill cuttings and other useless material that is generated during drilling, well or production operations.

(2) The operator shall ensure that any measurements are conducted in accordance with the flow system, flow calculation procedure and flow allocation procedure, approved under subsection 7(2).

61. (1) The operator shall ensure that group production of oil and gas from wells and injection of a fluid into wells is allocated on a *pro rata* basis, in accordance with the flow system, flow calculation procedure and flow allocation procedure approved under subsection 7(2).

(2) If a well is completed over multiple pools or zones, the operator shall ensure that production or injection volumes for the well are allocated on a *pro rata* basis to the pools or zones in accordance with the flow allocation procedure approved under subsection 7(2).

TESTING, MAINTENANCE AND NOTIFICATION

62. The operator shall ensure

(*a*) that meters and associated equipment are calibrated and maintained to ensure their continued accuracy;

(*b*) that equipment used to calibrate the flow system is calibrated in accordance with good measurement practices;

(*c*) that any component of the flow system that may have an impact on the accuracy or integrity of the flow system and that is not functioning in accordance with the manufacturer's specifications is repaired or replaced without delay, or, if it is not possible to do so without delay, corrective measures are taken

PARTIE 7

MESURAGE

DÉBIT ET VOLUME

60. (1) Sauf disposition contraire précisée dans l'approbation délivrée aux termes du paragraphe 7(2), l'exploitant veille à ce que soient mesurés et enregistrés le débit et le volume des fluides et matériaux suivants :

a) le fluide produit par chaque puits;

b) le fluide injecté dans chaque puits;

c) le fluide produit qui entre dans une installation, y compris dans une salle des accumulateurs, une installation de traitement ou une usine de transformation, ou qui en sort, y est utilisé ou est brûlé à la torche, est rejeté, est brûlé ou autrement éliminé;

d) l'air ou les matériaux injectés à des fins d'élimination, de stockage ou de recyclage, y compris les déblais de forage et autres matériaux inutilisables produits au cours des activités de forage, des travaux relatifs à un puits ou à des travaux de production.

(2) L'exploitant veille à ce que le mesurage soit effectué conformément au système d'écoulement et aux méthodes de calcul et de répartition du débit approuvés au titre du paragraphe 7(2).

61. (1) L'exploitant veille à ce que soient réparties au prorata la production regroupée de pétrole et de gaz des puits et l'injection de fluides dans les puits, conformément au système d'écoulement et aux méthodes de calcul et de répartition du débit approuvés au titre du paragraphe 7(2).

(2) Dans le cas d'un puits dont la complétion est réalisée sur plusieurs gisements ou couches, l'exploitant veille à ce que la production ou l'injection pour chaque gisement ou couche soit répartie au prorata selon la méthode de répartition du débit approuvée au titre du paragraphe 7(2).

ESSAIS, ENTRETIEN ET NOTIFICATION

62. L'exploitant veille au respect des exigences suivantes :

a) les compteurs et le matériel connexe sont entretenus et étalonnés de manière à assurer la précision des mesures;

b) l'équipement utilisé pour étalonner le système d'écoulement est étalonné conformément aux règles de l'art en matière de mesurage;

c) tout composant du système d'écoulement pouvant avoir des effets sur la précision ou sur l'intégrité du système d'écoulement et dont le fonctionnement n'est pas conforme aux spécifications du fabricant est réparé ou remplacé sans délai; en cas to minimize the impact on the accuracy and integrity of the flow system while the repair or replacement is proceeding; and

(*d*) that a conservation officer is notified, as soon as the circumstances permit, of any malfunction or failure of any flow system component that may have an impact on the accuracy of the flow system and of the corrective measures taken.

de retard inévitable, des mesures correctives sont prises entre-temps pour réduire au minimum ces effets;

d) un agent du contrôle de l'exploitation est avisé, aussitôt que les circonstances le permettent, de toute défectuosité ou défaillance d'un composant du système d'écoulement qui pourrait avoir des effets sur l'exactitude du système d'écoulement et des mesures correctives prises.

TRANSFER METERS

63. The operator shall ensure that

(*a*) a conservation officer is notified at least 14 days before the day on which any transfer meter prover or master meter used in conjunction with a transfer meter is calibrated; and

(*b*) a copy of the calibration certificate is submitted to the Chief Conservation Officer as soon as the circumstances permit, following completion of the calibration.

COMPTEURS DE TRANSFERT

63. L'exploitant veille au respect des exigences suivantes :

a) un agent du contrôle de l'exploitation est avisé au moins quatorze jours avant l'étalonnage d'un compteur étalon de transfert ou d'un compteur général lié à celui-ci;

b) une copie du certificat d'étalonnage est remise au délégué à l'exploitation aussitôt que les circonstances le permettent après l'étalonnage.

PRORATION TESTING FREQUENCY

64. The operator of a development well that is producing oil or gas shall ensure that sufficient proration tests are performed to permit reasonably accurate determination of the allocation of oil, gas and water production on a pool and zone basis.

FRÉQUENCE D'ESSAIS AU PRORATA

64. L'exploitant d'un puits d'exploitation produisant du pétrole ou du gaz veille à ce que le puits soit soumis à un nombre suffisant d'essais au prorata pour permettre de déterminer avec une précision suffisante la répartition de la production de pétrole, de gaz et d'eau par gisement et par couche.

PART 8

PRODUCTION CONSERVATION

RESOURCE MANAGEMENT

65. The operator shall ensure that

(*a*) maximum recovery from a pool or zone is achieved in accordance with good oilfield practices;

(*b*) wells are located and operated to provide for maximum recovery from a pool; and

(*c*) if there is reason to believe that infill drilling or implementation of an enhanced recovery scheme might result in increased recovery from a pool or field, studies on these methods are carried out and submitted to the Board.

PARTIE 8

RATIONALISATION DE LA PRODUCTION

GESTION DES RESSOURCES

65. L'exploitant veille au respect des exigences suivantes :

a) la récupération maximale d'un gisement ou d'une couche est réalisée selon les règles de l'art en matière d'exploitation pétrolière;

b) les puits sont disposés et exploités de manière à permettre la récupération maximale d'un gisement;

c) s'il y a lieu de croire que le forage intercalaire ou la mise en œuvre d'un plan de récupération assistée permettrait d'accroître la récupération d'un gisement ou d'un champ, ces méthodes font l'objet d'une étude qui est remise à l'Office.

COMMINGLED PRODUCTION

66. (1) No operator shall engage in commingled production except in accordance with the approval granted under subsection (2).

(2) The Board shall approve the commingled production if the operator demonstrates that it would not reduce the recovery from the pools or zones.

(3) The operator engaging in commingled production shall ensure that the total volume and the rate of production of each fluid produced is measured and the volume from each pool or zone is allocated in accordance with the requirements of Part 7.

PRODUCTION MÉLANGÉE

66. (1) Il est interdit à l'exploitant de se livrer à une production mélangée, sauf en conformité avec l'approbation accordée au paragraphe (2).

(2) L'Office approuve la production mélangée si l'exploitant démontre que celle-ci ne réduirait pas la récupération des gisements ou des couches.

(3) L'exploitant qui se livre à une production mélangée veille à ce que le volume total et le taux de production de chaque fluide produit soient mesurés et que le volume pour chaque gisement ou chaque couche soit réparti conformément aux exigences de la partie 7.

GAS FLARING AND VENTING

67. No operator shall flare or vent gas unless

(*a*) it is otherwise permitted in the approval issued under subsection 52(4) or in the authorization; or

(*b*) it is necessary to do so because of an emergency situation and the Board is notified in the daily drilling report, daily production report or in any other written or electronic form, as soon as the circumstances permit, of the flaring or venting and of the amount flared or vented.

OIL BURNING

68. No operator shall burn oil unless

(*a*) it is otherwise permitted in the approval issued under subsection 52(4) or in the authorization; or

(*b*) it is necessary to do so because of an emergency situation and the Board is notified in the daily drilling report, daily production report or in any other written or electronic form, as soon as the circumstances permit, of the burning and the amount burned.

PART 9

SUPPORT OPERATIONS

SUPPORT CRAFT

69. The operator shall ensure that all support craft are designed, constructed and maintained to supply the necessary support functions and operate safely in the foreseeable physical environmental conditions prevailing in the area in which they operate.

70. (1) The operator of a manned installation shall ensure that at least one support craft is

(*a*) available at a distance that is not greater than that required for a return time of twenty minutes; and

(*b*) suitably equipped to supply the necessary emergency services including rescue and first aid treatment for all personnel on the installation in the event of an emergency.

(2) If the support craft exceeds the distance referred to in paragraph (1)(*a*), both the installation manager and the person in charge of the support craft shall log this fact and the reason why the distance or time was exceeded.

(3) Under the direction of the installation manager, the support craft crew shall keep the craft in close proximity to the installation, maintain open communication channels with the installation and be prepared to conduct rescue operations during any activity or condition that presents an increased level of risk to the safety of personnel or the installation.

BRÛLAGE DE GAZ À LA TORCHE ET REJET DE GAZ DANS L'ATMOSPHÈRE

67. Il est interdit à l'exploitant de brûler du gaz à la torche ou de rejeter du gaz dans l'atmosphère, sauf dans les cas suivants :

a) le brûlage ou le rejet est par ailleurs permis aux termes de l'approbation accordée au titre du paragraphe 52(4) ou dans l'autorisation;

b) le brûlage ou le rejet est nécessaire pour remédier à une situation d'urgence, auquel cas l'Office en est avisé, aussitôt que les circonstances le permettent, dans le rapport journalier de forage ou le registre quotidien relatif à la production ou encore sous toute autre forme écrite ou électronique, avec indication des quantités brûlées ou rejetées.

BRÛLAGE DE PÉTROLE

68. Il est interdit à l'exploitant de brûler du pétrole, sauf dans les cas suivants :

a) le brûlage est par ailleurs permis aux termes de l'approbation accordée au titre du paragraphe 52(4) ou dans l'autorisation;

b) il est nécessaire pour remédier à une situation d'urgence, auquel cas l'Office en est avisé, aussitôt que les circonstances le permettent, dans le rapport journalier de forage ou le registre quotidien relatif à la production ou encore sous toute autre forme écrite ou électronique, avec indication des quantités brûlées.

PARTIE 9

OPÉRATIONS DE SOUTIEN

VÉHICULES DE SERVICE

69. L'exploitant veille à ce que tout véhicule de service soit conçu, construit et entretenu de manière à pouvoir remplir son rôle de soutien et fonctionner en toute sécurité dans les conditions environnementales qui règnent normalement dans la région desservie.

70. (1) L'exploitant d'une installation habitée veille à ce qu'au moins un véhicule de service soit :

a) disponible à une distance permettant une intervention d'au plus vingt minutes aller-retour;

b) équipé de manière à pouvoir fournir les services d'urgence nécessaires, y compris le secours et les premiers soins pour tout le personnel à l'installation au besoin.

(2) Le cas échéant, si le véhicule de service se trouve à une distance plus grande que celle prévue à l'alinéa (1)*a*), le chargé de projet et la personne responsable du véhicule de service doivent consigner ce fait et indiquer la raison pour laquelle la distance ou le délai n'a pas été respecté.

(3) Sous la direction du chargé de projet, le personnel attaché au véhicule de service doit tenir le véhicule à proximité de l'installation, maintenir ouvertes les voies de communication avec celle-ci et être prêt à mener des opérations de sauvetage durant toute activité ou dans toute situation qui présente un risque accru pour la sécurité du personnel ou de l'installation.

Safety Zone

71. (1) For the purposes of this section, the safety zone around an offshore installation consists of the area within a line enclosing and drawn at a distance of 500 m from the outer edge of the installation.

(2) A support craft shall not enter the safety zone without the consent of the installation manager.

(3) The operator shall take all reasonable measures to warn persons who are in charge of vessels and aircraft of the safety zone boundaries, of the facilities within the safety zone and of any related potential hazards.

PART 10

TRAINING AND COMPETENCY

72. The operator shall ensure that

(*a*) all personnel have, before assuming their duties, the necessary experience, training and qualifications and are able to conduct their duties safely, competently and in compliance with these Regulations; and

(*b*) records of the experience, training and qualifications of all personnel are kept and made available to the Board upon request.

PART 11

SUBMISSIONS, NOTIFICATIONS, RECORDS AND REPORTS

Reference to Names and Designations

73. When submitting any information for the purposes of these Regulations, the operator shall refer to each well, pool and field by the name given to it under sections 3 and 4, or if a zone, by its designation by the Board under section 4.

Surveys

74. (1) The operator shall ensure that a survey is used to confirm

(*a*) for an onshore well, the surface location; and

(*b*) for an offshore well, the location on the seafloor.

(2) The survey shall be certified by a person licensed under the *Canada Lands Surveyors Act*.

(3) The operator shall ensure that a copy of the survey plan filed with the Canada Lands Surveys Records is submitted to the Board.

Incidents and Near-misses

75. (1) The operator shall ensure that

(*a*) the Board is notified of any incident or near-miss as soon as the circumstances permit; and

(*b*) the Board is notified at least 24 hours in advance of any press release or press conference held by the operator concerning any incident or near-miss during any activity to which these Regulations apply, except in an emergency situation, in which

Zone de sécurité

71. (1) Pour l'application du présent article, la zone de sécurité autour d'une installation extracôtière est formée de la superficie se trouvant dans les 500 m à l'extérieur du périmètre de l'installation.

(2) Un véhicule de service ne peut entrer dans la zone de sécurité sans le consentement du chargé de projet.

(3) L'exploitant doit prendre toutes les mesures voulues pour aviser les responsables de navires ou d'aéronefs des limites de la zone de sécurité, du matériel qui s'y trouve et des risques éventuels y afférents.

PARTIE 10

FORMATION ET COMPÉTENCE

72. L'exploitant veille au respect des exigences suivantes :

a) avant d'assumer ses fonctions, tout le personnel doit avoir l'expérience, la formation et les qualifications voulues ainsi que la capacité d'exécuter ses fonctions en toute sécurité et de façon compétente, et ce, conformément au présent règlement;

b) les dossiers relatifs à l'expérience, la formation et les qualifications du personnel sont conservés et, sur demande, ils sont mis à la disposition de l'Office.

PARTIE 11

PRÉSENTATIONS, AVIS, REGISTRES ET RAPPORTS

Mention des noms et désignations

73. Au moment de la présentation de renseignements en application du présent règlement, l'exploitant y indique chaque puits, gisement ou champ par le nom qui lui est attribué en vertu des articles 3 et 4 ou, s'agissant d'une couche, par la désignation de l'Office en vertu de l'article 4.

Arpentage

74. (1) L'exploitant veille à ce qu'un arpentage soit effectué pour confirmer :

a) dans le cas d'un puits terrestre, l'emplacement en surface;

b) dans le cas d'un puits extracôtier, l'emplacement sur le fond marin.

(2) L'arpentage est certifié par une personne titulaire d'un permis en vertu de la *Loi sur les arpenteurs des terres du Canada*.

(3) L'exploitant veille à ce qu'une copie du plan d'arpentage déposé aux Archives d'arpentage des terres du Canada soit remise à l'Office.

Incidents et quasi-incidents

75. (1) L'exploitant veille au respect des exigences suivantes :

a) l'Office est avisé, aussitôt que les circonstances le permettent, de tout incident ou quasi-incident;

b) l'Office est avisé, au moins vingt-quatre heures avant la diffusion de tout communiqué ou la tenue de toute conférence de presse par l'exploitant, de tout incident ou quasi-incident survenu lors d'une activité visée par le présent règlement, sauf en case it shall be notified without delay before the press release or press conference.

(2) The operator shall ensure that

(*a*) any incident or near-miss is investigated, its root cause and causal factors identified and corrective action taken; and

(*b*) for any of the following incidents or near-misses, a copy of an investigation report identifying the root cause, causal factors and corrective action taken is submitted to the Board no later than 21 days after the day on which the incident or near-miss occurred:

(i) a lost or restricted workday injury,

(ii) death,

(iii) fire or explosion,

(iv) a loss of containment of any fluid from a well,

(v) an imminent threat to the safety of a person, installation or support craft, or

(vi) a significant pollution event.

SUBMISSION OF DATA AND ANALYSIS

76. (1) The operator shall ensure that a final copy of the results, data, analyses and schematics obtained from the following sources is submitted to the Board:

(*a*) testing, sampling and pressure surveys carried out as part of the well and field data acquisition programs referred to in section 49 and testing and sampling of formations referred to in section 51; and

(*b*) any segregation test or well operation.

(2) Unless otherwise indicated in these Regulations, the operator shall ensure that the results, data, analyses and schematics are submitted within 60 days after the day on which any activity referred to in paragraphs (1)(*a*) and (*b*) is completed.

RECORDS

77. The operator shall ensure that records are kept of

(*a*) all persons arriving, leaving or present on the installation;

(*b*) the location and movement of support craft, the emergency drills and exercises, incidents, near-misses, the quantities of consumable substances that are required to ensure the safety of operations and other observations and information critical to the safety of persons on the installation or the protection of the environment;

(*c*) daily maintenance and operating activities, including any activity that may be critical to the safety of persons on the installation, the protection of the environment or the prevention of waste;

(*d*) in the case of a production installation,

(i) the inspection of the installation and related equipment for corrosion and erosion and any resulting maintenance carried out,

(ii) the pressure, temperature and flow rate data for compressors and treating and processing facilities,

(iii) the calibration of meters and instruments,

(iv) the testing of surface and subsurface safety valves,

(v) the status of each well and the status of well operations, and

situation d'urgence, auquel cas avis lui est donné sans délai avant le communiqué ou la conférence de presse.

(2) L'exploitant veille au respect des exigences suivantes :

a) une enquête est menée à l'égard de chaque incident ou quasi-incident, sa cause première et les facteurs contributifs sont précisés et des mesures correctives sont prises;

b) un rapport d'enquête précisant la cause première de l'incident ou quasi-incident, les facteurs contributifs et les mesures correctives est remis à l'Office au plus tard vingt et un jours après l'incident ou quasi-incident, s'il s'agit :

(i) d'une blessure entraînant une perte de temps de travail,

(ii) d'une perte de vie,

(iii) d'un incendie ou d'une explosion,

(iv) d'une défaillance du confinement d'un fluide provenant d'un puits,

(v) d'une menace imminente à la sécurité d'une personne, d'une installation ou d'un véhicule de service,

(vi) d'un événement de pollution important.

PRÉSENTATION DE DONNÉES ET ANALYSES

76. (1) L'exploitant veille à ce que soient remis à l'Office les résultats, données, analyses et schémas définitifs fondés sur :

a) la mise à l'essai, l'échantillonnage et les relevés de pression effectués dans le cadre des programmes d'acquisition des données relatives aux puits et aux champs visés à l'article 49, et la mise à l'essai et l'échantillonnage prévus à l'article 51;

b) les essais de séparation ou les travaux relatifs à un puits.

(2) Sauf disposition contraire du présent règlement, l'exploitant veille à ce que les résultats, données, analyses et schémas soient présentés dans les soixante jours suivant la fin de toute activité mentionnée aux alinéas (1)*a*) et *b*).

REGISTRES

77. L'exploitant veille à ce que soient tenus des registres concernant :

a) les personnes qui arrivent à l'installation, qui s'y trouvent ou qui la quittent;

b) l'emplacement et les déplacements des véhicules de service, les exercices d'urgence, les incidents, les quasi-incidents, les quantités de substances consomptibles nécessaires à la sécurité des opérations et tout autre observation ou renseignement essentiel pour la sécurité des personnes se trouvant à l'installation ou la protection de l'environnement;

c) les activités quotidiennes d'entretien et d'exploitation, y compris toute activité essentielle pour la sécurité des personnes se trouvant à l'installation, la protection de l'environnement ou la prévention du gaspillage;

d) dans le cas d'une installation de production :

(i) les inspections de l'installation et du matériel connexe en vue de vérifier la présence de corrosion et d'érosion et les travaux d'entretien effectués par suite de ces inspections,

(ii) les données relatives à la pression, à la température et au débit des compresseurs, du matériel de traitement et de transformation,

(iii) l'étalonnage des compteurs et autres instruments,

(vi) the status of the equipment and systems critical to safety and protection of the environment including any unsuccessful test result or equipment failure leading to an impairment of the systems; and

(*e*) in the case of a floating installation, all installation movements, data, observations, measurements and calculations related to the stability and station-keeping capability of the installation.

METEOROLOGICAL OBSERVATIONS

78. The operator of an offshore installation shall ensure

(*a*) that the installation is equipped with facilities and equipment for observing, measuring and recording physical environmental conditions and that a comprehensive record of observations of physical environmental conditions is maintained onboard the installation; and

(*b*) that forecasts of meteorological conditions, sea states and ice movements are obtained and recorded each day and each time during the day that they change substantially from those forecasted.

DAILY PRODUCTION RECORD

79. The operator shall ensure that a daily production record, which includes the metering records and other information relating to the production of oil and gas and other fluids in respect of a pool or well, is retained and readily accessible to the Board until the field or well in which the pool is located is abandoned and at that time shall offer the record to the Board before destroying it.

MANAGEMENT OF RECORDS

80. The operator shall ensure that

(*a*) all processes are in place and implemented to identify, generate, control and retain records necessary to support operational and regulatory requirements; and

(*b*) the records are readily accessible for inspection by the Board.

FORMATION FLOW TEST REPORTS

81. The operator shall ensure that

(*a*) in respect of exploration and delineation wells, a daily record of formation flow test results is submitted to the Board; and

(*b*) in respect of all wells, a formation flow test report is submitted to the Board as soon as the circumstances permit, following completion of the test.

PILOT SCHEME

82. (1) For the purposes of this section, "pilot scheme" means a scheme that applies existing or experimental technology over a limited portion of a pool to obtain information on reservoir or production performance for the purpose of optimizing field development or improving reservoir or production performance.

(iv) les essais des vannes de sécurité de surface et de subsurface,

(v) l'état de chacun des puits et l'état d'avancement des travaux relatifs aux puits,

(vi) l'état de l'équipement et des systèmes essentiels à la sécurité et à la protection de l'environnement, y compris tout résultat négatif des essais et toute défaillance de l'équipement qui ont mené à un affaiblissement des systèmes;

e) dans le cas d'une installation flottante, les mouvements de l'installation et les données, observations, mesures et calculs relatifs à la stabilité de l'installation et à sa capacité de conserver sa position.

OBSERVATIONS MÉTÉOROLOGIQUES

78. L'exploitant d'une installation extracôtière veille au respect des exigences suivantes :

a) l'installation est dotée des moyens et de l'équipement nécessaires pour observer, mesurer et consigner les conditions environnementales et un rapport détaillé des observations de ces conditions est conservé à bord de l'installation;

b) les prévisions des conditions météorologiques, de l'état de la mer et du mouvement des glaces sont obtenues et consignées chaque jour, ainsi qu'à chaque fois qu'il y a des variations sensibles de ceux-ci.

REGISTRES QUOTIDIENS RELATIFS À LA PRODUCTION

79. L'exploitant veille à ce qu'un registre quotidien relatif à la production, contenant les dossiers relatifs aux compteurs et tout autre renseignement concernant la production de pétrole et de gaz et d'autres fluides dans un gisement ou un puits, soit conservé et soit facilement accessible à l'Office jusqu'à l'abandon du champ ou du puits dans lequel le gisement est situé, et il l'offre à l'Office avant de le détruire.

GESTION DES REGISTRES

80. L'exploitant veille au respect des exigences suivantes :

a) des processus sont en place et mis en œuvre pour identifier, produire, contrôler et conserver les registres requis pour répondre aux exigences opérationnelles et réglementaires;

b) les registres sont facilement accessibles à l'Office pour examen.

RAPPORTS RELATIFS AUX ESSAIS D'ÉCOULEMENT DE FORMATION

81. L'exploitant veille au respect des exigences suivantes :

a) pour les puits d'exploitation et de délimitation, un registre quotidien des résultats des essais d'écoulement de formation est remis à l'Office;

b) pour tous les puits, un rapport des essais d'écoulement de formation est remis à l'Office aussitôt que les circonstances le permettent après l'essai.

PROJET PILOTE

82. (1) Pour l'application du présent article, « projet pilote » s'entend de tout projet pour lequel on utilise une technique conventionnelle ou expérimentale dans une section limitée d'un gisement afin d'obtenir des renseignements sur le rendement du réservoir ou sur la production à des fins d'optimisation de la mise en valeur du champ ou d'amélioration du rendement du réservoir ou de la production.

(2) The operator shall ensure that interim evaluations of any pilot scheme respecting a pool, field or zone are submitted to the Board.

(3) When the operator completes a pilot scheme, the operator shall ensure that a report is submitted to the Board that sets out

(*a*) the results of the scheme and supporting data and analyses; and

(*b*) the operator's conclusions as to the potential of the scheme for application to full-scale production.

(2) L'exploitant veille à ce que des évaluations provisoires de tout projet pilote relatif à un gisement, un champ ou une couche soient remises à l'Office.

(3) Au terme d'un projet pilote, l'exploitant veille à ce que soit remis à l'Office un rapport faisant état :

a) des résultats du projet, avec les données et analyses à l'appui;

b) des conclusions de l'exploitant quant à la possibilité de passer à la mise en production à plein rendement.

DAILY REPORTS

83. The operator shall ensure that a copy of the following is submitted to the Board daily:

(*a*) the daily drilling report;

(*b*) the daily geological report, including any formation evaluation logs and data; and

(*c*) in the case of a production installation, a summary, in the form of a daily production report, of the records referred to in paragraph 77(*d*) and the daily production record.

RAPPORTS QUOTIDIENS

83. L'exploitant veille à ce que soit remis à l'Office quotidiennement :

a) le rapport journalier de forage;

b) le rapport géologique quotidien, y compris les diagraphies et les données relatives à l'évaluation de la formation;

c) dans le cas d'une installation de production, un résumé des registres visés à l'alinéa 77*d*) et du registre quotidien relatif à la production, sous forme d'un rapport de la production quotidienne.

MONTHLY PRODUCTION REPORT

84. (1) The operator shall ensure that a report summarizing the production data collected during the preceding month is submitted to the Board not later than the 15th day of each month.

(2) The report shall use established production accounting procedures.

RAPPORT MENSUEL CONCERNANT LA PRODUCTION

84. (1) L'exploitant veille à ce que soit présenté à l'Office, au plus tard le quinzième jour du mois, un rapport résumant les données de production du mois précédent.

(2) Le rapport de la production mensuelle est établi selon des méthodes reconnues de comptabilité de la production.

ANNUAL PRODUCTION REPORT

85. The operator shall ensure that, not later than March 31 of each year, an annual production report relating to the preceding year for a pool, field or zone is submitted to the Board including details on the performance, production forecast, reserve revision, reasons for significant deviations in well performance from predictions in previous annual production reports, gas conservation resources, efforts to maximize recovery and reduce costs, and any other information required to demonstrate how the operator manages and intends to manage the resource without causing waste.

RAPPORT ANNUEL DE PRODUCTION

85. L'exploitant veille à ce que soit présenté à l'Office, au plus tard le 31 mars de chaque année, un rapport annuel de la production de l'année précédente ayant trait à un gisement, un champ ou une couche et comprenant notamment des données sur le rendement, des prévisions concernant la production, une révision des réserves, une explication de tout écart marqué entre le rendement d'un puits et les prévisions contenues dans les rapports annuels de production antérieurs, les ressources affectées à la conservation du gaz, les efforts faits pour optimiser la récupération et réduire les coûts, et toute autre information qui démontre de quelle manière l'exploitant gère les ressources et entend les gérer à l'avenir sans gaspillage.

ENVIRONMENTAL REPORTS

86. (1) For each production project, the operator shall ensure that, not later than March 31 of each year, an annual environmental report relating to the preceding year is submitted to the Board and includes

(*a*) for an offshore installation, a summary of the general environmental conditions during the year and a description of ice management activities; and

(*b*) a summary of environmental protection matters during the year, including a summary of any incidents that may have an environmental impact, discharges that occurred and waste material that was produced, a discussion of efforts undertaken to

RAPPORT SUR LES CONDITIONS ENVIRONNEMENTALES

86. (1) Pour chaque projet de production, l'exploitant veille à ce que soit présenté à l'Office, au plus tard le 31 mars de chaque année, un rapport annuel sur les conditions environnementales pour l'année précédente et contenant :

a) dans le cas d'une installation extracôtière, un résumé des conditions environnementales générales de l'année ainsi qu'une description des activités de gestion des glaces;

b) un résumé des situations afférentes à la protection de l'environnement survenues au cours de l'année, y compris des données sommaires sur les incidents pouvant avoir des effets environnementaux, les rejets survenus et les déchets produits, reduce pollution and waste material and a description of environmental contingency plan exercises.

(2) For each drilling installation for an exploration or delineation well, the operator shall ensure that an environmental report relating to each well is submitted to the Board within 90 days after the rig release date and includes

(*a*) a description of the general environmental conditions during the drilling program and a description of ice management activities and downtime caused by weather or ice; and

(*b*) a summary of environmental protection matters during the drilling program, including a summary of spills, discharges occurred and waste material produced, a discussion of efforts undertaken to reduce them, and a description of environmental contingency plan exercises.

ANNUAL SAFETY REPORT

87. The operator shall ensure that, not later than March 31 of each year, an annual safety report relating to the preceding year is submitted to the Board and includes

(*a*) a summary of lost or restricted workday injuries, minor injuries and safety-related incidents and near-misses that have occurred during the preceding year; and

(*b*) a discussion of efforts undertaken to improve safety.

WELL HISTORY REPORT

88. (1) The operator shall ensure that a well history report is prepared for every well drilled by the operator under the well approval and that the report is submitted to the Board.

(2) The well history report shall contain a record of all operational, engineering, petrophysical and geological information that is relevant to the drilling and evaluation of the well.

WELL OPERATIONS REPORT

89. (1) The operator shall ensure that a report including the following information is submitted to the Board within 30 days after the end of a well operation:

(*a*) a summary of the well operation, including any problems encountered during the well operation;

(*b*) a description of the completion fluid properties;

(*c*) a schematic of, and relevant engineering data on, the downhole equipment, tubulars, Christmas tree and production control system;

(*d*) details of any impact of the well operation on the performance of the well, including any effect on recovery; and

(*e*) for any well completion, suspension or abandonment, the rig release date.

(2) The report shall be signed and dated by the operator or the operator's representative.

un exposé des efforts accomplis pour réduire la pollution et les déchets et une description des exercices de simulation du plan d'urgence environnementale.

(2) Pour chaque installation de forage d'un puits d'exploration ou de délimitation, l'exploitant veille à ce que soit présenté à l'Office pour chaque puits, dans les quatre-vingt-dix jours suivant la date de libération de l'appareil de forage, un rapport sur les conditions environnementales qui contient ce qui suit :

a) une description des conditions environnementales générales dans lesquelles le programme de forage a été exécuté, ainsi qu'une description des activités de gestion des glaces et un relevé des périodes d'arrêt imputables aux conditions atmosphériques ou aux glaces;

b) un résumé des situations afférentes à la protection de l'environnement survenues durant l'exécution du programme de forage, y compris des données sommaires sur les déversements et les rejets survenus et sur les déchets produits, un exposé des efforts accomplis pour réduire ceux-ci, et une description des exercices de simulation du plan d'urgence environnementale.

RAPPORT ANNUEL SUR LA SÉCURITÉ

87. L'exploitant veille à ce que soit présenté à l'Office, au plus tard le 31 mars de chaque année, un rapport annuel sur la sécurité portant sur l'année précédente et contenant ce qui suit :

a) un résumé des blessures entraînant une perte de temps de travail, des blessures sans gravité et des incidents et quasi-incidents en matière de sécurité survenus au cours de l'année;

b) un exposé des mesures prises pour renforcer la sécurité.

RAPPORT FINAL DU PUITS

88. (1) L'exploitant veille à ce qu'un rapport final soit établi pour chacun des puits qu'il a forés aux termes de l'approbation relative au puits et à ce que le rapport soit remis à l'Office.

(2) Le rapport final doit contenir tous les renseignements opérationnels, techniques, pétrophysiques et géologiques concernant le forage et l'évaluation du puits.

RAPPORT D'EXPLOITATION DU PUITS

89. (1) L'exploitant veille à ce que soit remis à l'Office, dans les trente jours suivant la fin des travaux relatifs à un puits, un rapport qui contient :

a) un résumé des travaux, y compris les problèmes survenus au cours de ceux-ci;

b) une description des propriétés des fluides de complétion;

c) un schéma et les détails techniques des équipements de fond, des tubulaires, de la tête d'éruption et du système de contrôle de la production;

d) les détails de toute incidence que l'exploitation du puits pourrait avoir sur son rendement, y compris sur la récupération;

e) la date de libération de l'appareil de forage en ce qui concerne la complétion, la suspension de l'exploitation ou l'abandon d'un puits.

(2) Le rapport est daté et signé par l'exploitant ou son représentant.

OTHER REPORTS

90. The operator shall ensure that the Board is made aware, at least once a year, of any report containing relevant information regarding applied research work or studies obtained or compiled by the operator relating to the operator's work or activities and that a copy of any report is submitted to the Board on request.

PART 12

CONSEQUENTIAL AMENDMENTS, TRANSITIONAL PROVISION, REPEALS AND COMING INTO FORCE

CONSEQUENTIAL AMENDMENTS

Canada Oil and Gas Certificate of Fitness Regulations

91. (1) The definition "société d'accréditation" in section 2 of the French version of the *Canada Oil and Gas Certificate of Fitness Regulations*[1] is repealed.

(2) The definition "certifying authority" in section 2 of the English version of the Regulations is replaced by the following:

"certifying authority" means, for the purposes of section 5.12 of the Act, the American Bureau of Shipping, Bureau Veritas, Det norskeVeritas Classification A/S, Germanischer Lloyd or Lloyd's Register North America, Inc. (*autorité*)

(3) Section 2 of the French version of the Regulations is amended by adding the following in alphabetical order:

« autorité » Pour l'application de l'article 5.12 de la Loi, s'entend de l'American Bureau of Shipping, du Bureau Veritas, du Det norskeVeritas Classification A/S, du Germanischer Lloyd ou du Lloyd's Register North America, Inc. (*certifying authority*)

92. Section 4 of the Regulations is replaced by the following:

4. (1) The following installations are prescribed for the purposes of section 5.12 of the Act:

(*a*) each production installation, accommodation installation and diving installation at an offshore production site; and

(*b*) each drilling installation, diving installation and accommodation installation at an offshore drill site.

(2) Subject to subsections (3) and (5) and section 5, a certifying authority may issue a certificate of fitness in respect of the installations referred to in subsection (1), if the certifying authority

(*a*) determines that, in relation to the production or drill site or region in which the particular installation is to be operated, the installation

(i) is designed, constructed, transported and installed or established in accordance with

(A) Parts I to III of the *Canada Oil and Gas Installations Regulations*,

[1] SOR/96-114

AUTRES RAPPORTS

90. L'exploitant veille à ce que l'Office soit prévenu, au moins une fois l'an, de tout rapport renfermant de l'information utile sur des études ou des travaux de recherche appliquée qu'il a obtenus ou compilés concernant ses activités et veille à ce qu'il lui en soit remis copie, sur demande.

PARTIE 12

MODIFICATIONS CORRÉLATIVES, DISPOSITION TRANSITOIRE, ABROGATIONS ET ENTRÉE EN VIGUEUR

MODIFICATIONS CORRÉLATIVES

Règlement sur les certificats de conformité liés à l'exploitation du pétrole et du gaz au Canada

91. (1) La définition de « société d'accréditation », à l'article 2 de la version française du *Règlement sur les certificats de conformité liés à l'exploitation du pétrole et du gaz au Canada*[1], est abrogée.

(2) La définition de « certifying authority », à l'article 2 de la version anglaise du même règlement, est remplacée par ce qui suit :

"certifying authority" means, for the purposes of section 5.12 of the Act, the American Bureau of Shipping, Bureau Veritas, Det norskeVeritas Classification A/S, Germanischer Lloyd or Lloyd's Register North America, Inc. (*autorité*)

(3) L'article 2 de la version française du même règlement est modifié par adjonction, selon l'ordre alphabétique, de ce qui suit :

« autorité » Pour l'application de l'article 5.12 de la Loi, s'entend de l'American Bureau of Shipping, du Bureau Veritas, du Det norskeVeritas Classification A/S, du Germanischer Lloyd ou du Lloyd's Register North America, Inc. (*certifying authority*)

92. L'article 4 du même règlement est remplacé par ce qui suit :

4. (1) Pour l'application de l'article 5.12 de la Loi, les installations ci-après sont visées :

a) une installation de production, une installation d'habitation et une installation de plongée situées à un emplacement de production au large des côtes;

b) une installation de forage, une installation de plongée et une installation d'habitation situées à un emplacement de forage au large des côtes.

(2) Sous réserve des paragraphes (3) et (5) et de l'article 5, l'autorité peut délivrer un certificat de conformité à l'égard d'une installation visée au paragraphe (1) si :

a) d'une part, elle constate que, eu égard à l'emplacement ou à la région de production ou de forage où l'installation en cause est destinée à être exploitée, celle-ci :

(i) est conçue, construite, transportée et installée ou aménagée conformément aux dispositions suivantes :

(A) les parties I à III du *Règlement sur les installations pétrolières et gazières au Canada*,

[1] DORS/96-114

(B) the provisions of the *Oil and Gas Occupational Safety and Health Regulations* listed in Part 1 of the schedule to these Regulations, and

(C) the provisions of the *Canada Oil and Gas Diving Regulations* listed in Part 2 of the schedule to these Regulations, if the installation includes a dependent diving system,

(ii) is fit for the purpose for which it is to be used and can be operated safely without polluting the environment, and

(iii) will continue to meet the requirements of subparagraphs (i) and (ii) for the period of validity that is endorsed on the certificate of fitness if the installation is maintained in accordance with the inspection, maintenance and weight control programs submitted to and approved by the certifying authority under subsection (5); and

(*b*) carries out the scope of work in respect of which the certificate of fitness is issued.

(3) For the purposes of subparagraph (2)(*a*)(i), the certifying authority may substitute, for any equipment, methods, measure or standard required by any Regulations referred to in that subparagraph, equipment, methods, measures or standards the use of which is authorized by the Chief or Chief Conservation Officer, as applicable under section 16 of the Act.

(4) The certifying authority shall endorse on any certificate of fitness it issues details of every limitation on the operation of the installation that is necessary to ensure that the installation meets the requirements of paragraph (2)(*a*).

(5) The certifying authority shall not issue a certificate of fitness unless, for the purpose of enabling the certifying authority to determine whether the installation meets the requirements of paragraph (2)(*a*) and to carry out the scope of work referred to in paragraph (2)(*b*),

(*a*) the person applying for the certificate

(i) provides the certifying authority with all the information required by the certifying authority,

(ii) carries out or assists the certifying authority to carry out every inspection, test or survey required by the certifying authority, and

(iii) submits to the certifying authority an inspection and monitoring program, a maintenance program and a weight control program for approval; and

(*b*) if the programs are adequate to ensure and maintain the integrity of the installation, the certifying authority approves the programs referred to in subparagraph (*a*)(iii).

93. (1) Paragraph 6(2)(*a*) of the Regulations is replaced by the following:

(*a*) is sufficiently detailed to permit the certifying authority to determine whether the installation meets the requirements of paragraph 4(2)(*a*); and

(2) Paragraph 6(2)(*b*) of the Regulations is amended by striking out "and" at the end of subparagraph (v) and by adding the following after subparagraph (vi):

(vii) the structures, facilities, equipment and systems critical to safety, and to the protection of the natural environment, are in place and functioning appropriately, and

(viii) in respect of an offshore drilling installation or an offshore production installation, the structures, facilities, equipment and systems to meet the requirements of the

(B) les dispositions du *Règlement sur la sécurité et la santé au travail (pétrole et gaz)* énumérées à la partie 1 de l'annexe du présent règlement,

(C) dans les cas où l'installation comprend un système de plongée non autonome, les dispositions du *Règlement sur les opérations de plongée liées aux activités pétrolières et gazières au Canada* énumérées à la partie 2 de l'annexe du présent règlement,

(ii) se prête à l'utilisation prévue et peut être exploitée en toute sécurité sans polluer l'environnement,

(iii) continuera de répondre aux exigences des sous-alinéas (i) et (ii) pour la période de validité inscrite sur le certificat de conformité si l'installation est entretenue conformément aux programmes d'inspection, de maintenance et de contrôle de poids présentés à l'autorité et approuvés par elle aux termes du paragraphe (5);

b) d'autre part, elle exécute le plan de travail à l'égard duquel le certificat de conformité est délivré.

(3) Pour l'application du sous-alinéa (2)*a*)(i), l'autorité peut remplacer l'équipement, les méthodes, les mesures ou les normes exigés par un règlement visé à ce sous-alinéa par ceux dont l'utilisation est autorisée par le délégué ou le délégué à l'exploitation, selon le cas, en vertu de l'article 16 de la Loi.

(4) L'autorité doit inscrire sur tout certificat de conformité qu'elle délivre le détail de toute restriction à l'exploitation de l'installation qui s'impose pour que l'installation réponde aux exigences de l'alinéa (2)*a*).

(5) Pour être en mesure d'établir si l'installation répond aux exigences de l'alinéa (2)*a*) et d'exécuter le plan de travail visé à l'alinéa (2)*b*), l'autorité ne doit délivrer un certificat de conformité que si :

a) la personne qui en fait la demande :

(i) fournit à l'autorité tous les renseignements exigés par cette dernière,

(ii) exécute toute inspection, tout essai ou toute étude exigés par l'autorité ou aide celle-ci à les exécuter,

(iii) soumet à l'approbation de l'autorité un programme d'inspection et de surveillance, un programme de maintenance et un programme de contrôle de poids;

b) l'autorité approuve ceux des programmes visés au sous-alinéa *a*)(iii) qui permettent de garantir et de préserver l'intégrité de l'installation.

93. (1) L'alinéa 6(2)*a*) du même règlement est remplacé par ce qui suit :

a) est suffisamment détaillé pour permettre à l'autorité d'établir si l'installation répond aux exigences de l'alinéa 4(2)*a*);

(2) L'alinéa 6(2)*b*) du même règlement est modifié par adjonction, après le sous-alinéa (vi), de ce qui suit :

(vii) les structures, le matériel, les équipements et les systèmes essentiels à la sécurité et à la protection du milieu naturel sont en place et fonctionnent de façon appropriée,

(viii) à l'égard d'une installation de forage au large des côtes ou d'une installation de production au large des côtes, les structures, le matériel, les équipements et les systèmes conformes aux exigences des dispositions du *Règlement sur* provisions of the *Canada Oil and Gas Drilling and Production Regulations* listed in Part 3 of the schedule to these Regulations are in place and functioning appropriately.

94. Subsections 7(1) and (2) of the Regulations are replaced by the following:

7. (1) If the certifying authority determines that, when the installation is maintained in accordance with the programs submitted to it under subparagraph 4(5)(*a*)(iii), the installation will meet the requirements of paragraph 4(2)(*a*) for a period of at least five years, the certifying authority shall endorse on the certificate of fitness an expiration date that is five years after the date of issuance.

(2) If the period of time referred to in subsection (1) is less than five years, the certifying authority shall endorse on the certificate of fitness an expiration date that is the number of years or months in that lesser period after the date of issuance.

95. Subparagraphs 9(1)(*a*)(i) and (ii) of the Regulations are replaced by the following:

(i) that any of the information submitted under subsection 4(5) was incorrect and that the certificate of fitness would not have been issued if that information had been correct,

(ii) that the installation no longer meets the requirements of paragraph 4(2)(*a*), or

96. The French version of the Regulations is amended by replacing "société d'accréditation" and "société" with "autorité" in the following provisions with any necessary modifications:

(*a*) the definition "plan de travail" in section 2;

(*b*) section 5;

(*c*) subsection 6(1);

(*d*) subsection 8(1);

(*e*) section 9;

(*f*) the heading before section 10; and

(*g*) section 10.

97. The schedule to the Regulations is replaced by the schedule set out in the schedule to these Regulations.

Canada Oil and Gas Installations Regulations

98. (1) The definition "société d'accréditation" in subsection 2(1) of the French version of the *Canada Oil and Gas Installations Regulations*[2] is repealed.

(2) The expression "(*société d'accréditation*)" at the end of the definition "certifying authority" in subsection 2(1) of the English version of the Regulations is replaced by the expression "(*autorité*)".

(3) Subsection 2(1) of the French version of the Regulations is amended by adding the following in alphabetical order:

« autorité » S'entend au sens de l'article 2 du *Règlement sur les certificats de conformité liés à l'exploitation du pétrole et du gaz au Canada*. (*certifying authority*)

[2] SOR/96-118

le forage et la production de pétrole et de gaz au Canada énumérées à la partie 3 de l'annexe du présent règlement sont en place et fonctionnent de façon appropriée.

94. Les paragraphes 7(1) et (2) du même règlement sont remplacés par ce qui suit :

7. (1) Si l'autorité constate que l'installation, lorsqu'elle est entretenue conformément aux programmes qui lui ont été soumis en application du sous-alinéa 4(5)*a*)(iii), répondra aux exigences de l'alinéa 4(2)*a*) pour une période d'au moins cinq ans, l'autorité inscrit sur le certificat de conformité une date d'expiration qui suit de cinq ans la date de délivrance.

(2) Si la période visée au paragraphe (1) est inférieure à cinq ans, l'autorité inscrit sur le certificat de conformité une date d'expiration qui suit la date de délivrance du nombre d'années ou de mois correspondant à cette période moindre.

95. Les sous-alinéas 9(1)*a*)(i) et (ii) du même règlement sont remplacés par ce qui suit :

(i) des renseignements fournis aux termes du paragraphe 4(5) sont incorrects, et le certificat n'aurait pas été délivré si ces renseignements avaient été corrects,

(ii) l'installation ne répond plus aux exigences de l'alinéa 4(2)*a*),

96. Dans les passages ci-après de la version française du même règlement, « société d'accréditation » et « société » sont remplacés par « autorité » avec les adaptations nécessaires :

***a*) la définition de « plan de travail » à l'article 2;**

***b*) l'article 5;**

***c*) le paragraphe 6(1);**

***d*) le paragraphe 8(1);**

***e*) l'article 9;**

***f*) l'intertitre précédant l'article 10;**

***g*) l'article 10.**

97. L'annexe du même règlement est remplacée par l'annexe figurant à l'annexe du présent règlement.

Règlement sur les installations pétrolières et gazières au Canada

98. (1) La définition de « société d'accréditation », au paragraphe 2(1) de la version française du *Règlement sur les installations pétrolières et gazières au Canada*[2], est abrogée.

(2) La mention « (*société d'accréditation*) » qui figure à la fin de la définition de « certifying authority », au paragraphe 2(1) de la version anglaise du même règlement, est remplacée par « (*autorité*) ».

(3) Le paragraphe 2(1) de la version française du même règlement est modifié par adjonction, selon l'ordre alphabétique, de ce qui suit :

« autorité » S'entend au sens de l'article 2 du *Règlement sur les certificats de conformité liés à l'exploitation du pétrole et du gaz au Canada*. (*certifying authority*)

[2] DORS/96-118

99. Paragraph 14(1)(*c*) of the Regulations is replaced by the following:

(*c*) drilling safety systems and associated equipment will operate safely and in accordance with the manufacturer's specifications;

100. The portion of subsection 64(1) of the Regulations before paragraph (*a*) is replaced by the following:

64. (1) Subject to subsection (2), every operator shall prepare, adhere to and maintain, in respect of every offshore installation, an operations manual that contains the following data:

101. The French version of the Regulations is amended by replacing "société d'accréditation" with "autorité" in the following provisions with any necessary modifications:

(*a*) the definition "certificat de conformité" in subsection 2(1);

(*b*) subsection 68(1);

(*c*) subsections 68(3) and (4); and

(*d*) section 69.

TRANSITIONAL PROVISION

102. An operator at the time of the coming into force of these Regulations shall comply with the requirements of section 5.

REPEALS

103. The *Canada Oil and Gas Drilling Regulations*[3] are repealed.

104. The *Canada Oil and Gas Production and Conservation Regulations*[4] are repealed.

COMING INTO FORCE

105. These Regulations come into force on December 31, 2009.

SCHEDULE
(Section 97)

SCHEDULE
(Paragraphs 4(2)(a) and 6(2)(b))

CERTIFICATION STANDARDS

PART 1

PROVISIONS OF OIL AND GAS OCCUPATIONAL SAFETY AND HEALTH REGULATIONS

1. Sections 3.2 to 3.11
2. Section 5.1
3. Section 6.3
4. Sections 7.1 to 7.6
5. Section 9.5
6. Sections 9.11 and 9.12

[3] SOR/79-82
[4] SOR/90-791

99. L'alinéa 14(1)*c*) du même règlement est remplacé par ce qui suit :

c) les systèmes de sécurité pour le forage et le matériel connexe fonctionnent de façon sûre et conformément aux spécifications du fabricant;

100. Le passage du paragraphe 64(1) du même règlement précédant l'alinéa *a*) est remplacé par ce qui suit :

64. (1) Sous réserve du paragraphe (2), l'exploitant doit préparer, respecter et conserver pour toute installation au large des côtes un manuel d'exploitation qui contient les données suivantes :

101. Dans les passages ci-après de la version française du même règlement, « société d'accréditation » est remplacé par « autorité » avec les adaptations nécessaires :

***a*) la définition de « certificat de conformité » au paragraphe 2(1);**

***b*) le paragraphe 68(1);**

***c*) les paragraphes 68(3) et (4);**

***d*) l'article 69.**

DISPOSITION TRANSITOIRE

102. L'exploitant est tenu de se conformer aux exigences de l'article 5 à la date d'entrée en vigueur du présent règlement.

ABROGATIONS

103. Le *Règlement concernant le forage des puits de pétrole et de gaz naturel au Canada*[3] est abrogé.

104. Le *Règlement sur la production et la rationalisation de l'exploitation du pétrole et du gaz au Canada*[4] est abrogé.

ENTRÉE EN VIGUEUR

105. Le présent règlement entre en vigueur le 31 décembre 2009.

ANNEXE
(article 97)

ANNEXE
(alinéas 4(2)a) et 6(2)b))

NORMES DE CERTIFICATION

PARTIE 1

DISPOSITIONS DU RÈGLEMENT SUR LA SÉCURITÉ ET LA SANTÉ AU TRAVAIL (PÉTROLE ET GAZ)

1. Articles 3.2 à 3.11
2. Article 5.1
3. Article 6.3
4. Articles 7.1 à 7.6
5. Article 9.5
6. Articles 9.11 et 9.12

[3] DORS/79-82
[4] DORS/90-791

PART 1 — *Continued*

PROVISIONS OF OIL AND GAS OCCUPATIONAL SAFETY AND HEALTH REGULATIONS — *Continued*

7. Subsection 9.14(1)
8. Subsection 10.6(1)
9. Sections 10.9 to 10.11
10. Sections 10.14 to 10.16
11. Section 10.18
12. Sections 10.24 and 10.25
13. Section 10.27
14. Sections 10.35 to 10.37
15. Subsection 10.38(1)
16. Subsection 10.38(4)
17. Section 11.7
18. Section 11.9
19. Section 13.11
20. Subsection 13.16(4)
21. Section 14.13
22. Section 14.19
23. Sections 15.3 to 15.5
24. Sections 15.9 to 15.11
25. Section 15.13
26. Sections 15.21 and 15.22
27. Section 15.44
28. Subsections 15.47(1) and (2)
29. Subsection 15.49(2)
30. Section 15.50
31. Section 17.13
32. Paragraphs 17.14(*b*) and (*c*)
33. Paragraph 17.14(*e*)
34. Subparagraph 17.14(*f*)(i)
35. Section 18.2
36. Sections 18.6 to 18.8

PART 2

PROVISIONS OF CANADA OIL AND GAS DIVING REGULATIONS

1. Paragraphs 9(5)(*h*) to (*j*)
2. Subsection 12(1)
3. Paragraph 12(2)(*d*)
4. Paragraph 12(2)(*g*)
5. Paragraph 12(2)(*i*)

PARTIE 1 (*suite*)

DISPOSITIONS DU RÈGLEMENT SUR LA SÉCURITÉ ET LA SANTÉ AU TRAVAIL (PÉTROLE ET GAZ) (*suite*)

7. Paragraphe 9.14(1)
8. Paragraphe 10.6(1)
9. Articles 10.9 à 10.11
10. Articles 10.14 à 10.16
11. Article 10.18
12. Articles 10.24 et 10.25
13. Article 10.27
14. Articles 10.35 à 10.37
15. Paragraphe 10.38(1)
16. Paragraphe 10.38(4)
17. Article 11.7
18. Article 11.9
19. Article 13.11
20. Paragraphe 13.16(4)
21. Article 14.13
22. Article 14.19
23. Articles 15.3 à 15.5
24. Articles 15.9 à 15.11
25. Article 15.13
26. Articles 15.21 et 15.22
27. Article 15.44
28. Paragraphes 15.47(1) et (2)
29. Paragraphe 15.49(2)
30. Article 15.50
31. Article 17.13
32. Alinéas 17.14*b*) et *c*)
33. Alinéa 17.14*e*)
34. Sous-alinéa 17.14*f*)(i)
35. Article 18.2
36. Articles 18.6 à 18.8

PARTIE 2

DISPOSITIONS DU RÈGLEMENT SUR LES OPÉRATIONS DE PLONGÉE LIÉES AUX ACTIVITÉS PÉTROLIÈRES ET GAZIÈRES AU CANADA

1. Alinéas 9(5)*h*) à *j*)
2. Paragraphe 12(1)
3. Alinéa 12(2)*d*)
4. Alinéa 12(2)*g*)
5. Alinéa 12(2)*i*)

PART 2 — *Continued*

PROVISIONS OF CANADA OIL AND GAS DIVING REGULATIONS — *Continued*

6. Paragraphs 12(2)(*k*) to (*p*)
7. Section 13
8. Sections 14 to 17
9. Paragraph 18(*a*)
10. Paragraph 18(*c*)
11. Subsection 19(1)
12. Paragraph 19(2)(*a*)
13. Section 23
14. Paragraph 25(*a*)

PART 3

PROVISIONS OF CANADA OIL AND GAS DRILLING AND PRODUCTION REGULATIONS

1. Paragraph 5(2)(*e*), except in respect of support craft
2. Paragraph 19(*i*)
3. Paragraph 22(*b*)
4. Section 23
5. Section 25
6. Paragraph 26(*b*)
7. Sections 27 to 30
8. Sections 34 and 35
9. Subsection 36(1)
10. Section 37
11. Paragraphs 45(*a*) and (*b*)
12. Sections 47 and 48
13. Paragraphs 62(*a*) to (*c*)

REGULATORY IMPACT ANALYSIS STATEMENT

(This statement is not part of the regulations.)

Issue and objectives

The *Drilling and Production Regulations* are an amalgamation and modernization of the *Drilling Regulations* and the *Production and Conservation Regulations* that currently exist, in mirror form, under the *Canada Oil and Gas Operations Act* (COGOA) and the

PARTIE 2 (*suite*)

DISPOSITIONS DU RÈGLEMENT SUR LES OPÉRATIONS DE PLONGÉE LIÉES AUX ACTIVITÉS PÉTROLIÈRES ET GAZIÈRES AU CANADA (*suite*)

6. Alinéas 12(2)*k*) à *p*)
7. Article 13
8. Articles 14 à 17
9. Alinéa 18*a*)
10. Alinéa 18*c*)
11. Paragraphe 19(1)
12. Alinéa 19(2)*a*)
13. Article 23
14. Alinéa 25*a*)

PARTIE 3

DISPOSITIONS DU RÈGLEMENT SUR LE FORAGE ET LA PRODUCTION DE PÉTROLE ET DE GAZ AU CANADA

1. Alinéa 5(2)*e*), à l'exception des véhicules de service
2. Alinéa 19*i*)
3. Alinéa 22*b*)
4. Article 23
5. Article 25
6. Alinéa 26*b*)
7. Articles 27 à 30
8. Articles 34 et 35
9. Paragraphe 36(1)
10. Article 37
11. Alinéas 45*a*) et *b*)
12. Articles 47 et 48
13. Alinéas 62*a*) à *c*)

RÉSUMÉ DE L'ÉTUDE D'IMPACT DE LA RÉGLEMENTATION

(Ce résumé ne fait pas partie des règlements.)

Question et objectifs

Le *Règlement sur le forage et la production* est une fusion et une mise à jour du *Règlement concernant le forage* et du *Règlement sur la production et la rationalisation de l'exploitation du pétrole et du gaz* qui existent actuellement, structurés selon le