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State of Alaska,
Department of Natural Resources,
Division of Oil and Gas

Decommissioning, Removal, and Restoration Regulatory Review

Executive Summary

November 2014

ES.1 Introduction

The oil and natural gas production and transportation infrastructure located on state lands is considerable. On the North Slope, tens of dozens of miles of gravel roads, several manmade offshore islands, and acres of drilling pads form the backbone of the production of infrastructure. Miles of gathering and other small diameter pipelines move produced oil and natural gas from wells to production and processing facilities, from where it moves in miles of larger-diameter pipeline to Pump Station 1 and then south to Valdez. In Cook Inlet, 16 offshore platforms are installed on state leases, as are numerous well pads, processing facilities, and pipelines.

ES.1-1 DR&R—A Primer

Alaska's oil and natural gas reserves are a finite resource—at some time, Prudhoe Bay, Kuparuk, and every other field in Alaska will reach a point where the costs of production exceed the value of production. When that point is reached, the holder of the lease(s) will either (1) sell the assets to another company that believes there is still value to be obtained, or (2) cease operations and relinquish the lease. Regardless of how many times (1) occurs, (2) is inevitable.

Under the terms of state leases, at the cessation of operations, "all improvements such as roads, pads, and wells must either be abandoned and the sites rehabilitated by the lessee to the satisfaction of the state..." This end-of-life removal of improvements is referred to as decommissioning, removal, and restoration (DR&R). DR&R activities generally involve removal of infrastructure (roads, facilities, pipelines), the plugging and abandoning (P&A) of wells, and the environmental restoration of the area (for example, rehabilitating areas of tundra).

When one company sells its assets to another, under the terms of state leases, the selling company retains the responsibility to conduct DR&R activities for all improvements it placed on a lease, regardless of whether the producer still holds the lease or not (the current state lease form reads in relevant part: "The lessee shall remain liable for all obligations under this lease accruing prior to the approval by the state of any assignment, sublease, or other transfer of an interest in this lease.") To provide a current example, under the terms of its lease, BP and its original partners will remain liable for removing all improvements associated with the Endicott field (if so directed by the state) despite the fact that the leases and assets have been purchased by Hilcorp.

ES.1-2 DR&R in Alaska To Date

To date, DR&R issues in Alaska have largely been relegated to the back burner—the State's fields still possess significant value, and operators are profitable and continue development and exploration work. However, DR&R issues are on the horizon and now on the radar of state regulators—the bankruptcy of Pacific Energy and abandonment of its Osprey platform nearly resulted in the ownership of the platform (and the associated DR&R costs) reverting to the state.

Although this was an isolated incident, the oil and gas sector in Alaska is changing, and with it the risk of other similar situations. Since the start of production from the Swanson River field in 1958, large, well-capitalized, multinational corporations have discovered and operated the majority of the state's fields. During that time, when operators of a field changed, it was generally one large, well-capitalized multinational replacing another.

Smaller firms have been active in the exploration for oil and gas in Cook Inlet and on the North Slope for more than a decade. However, as the fields in Cook Inlet and on the North Slope mature, a greater number of these smaller, less-well-capitalized firms are emerging as owners and operators in both producing basins. In addition, a number of ownership changes are now being realized, and some of the firms entering the state have not worked in Alaska before. These transitions are common in the oil and gas sector, and have been seen in oil and gas basins throughout the Lower 48 and internationally.

As Alaska's oil and gas basins continue to mature, it is likely that greater numbers of smaller, less-well-capitalized firms will enter the marketplace; with this shift, there is an increased risk that a company or partnership may run out of capital and declare bankruptcy or dissolve, abandoning wells or facilities in the state, and leaving the state holding the bag with respect to the DR&R costs associated with the abandoned wells or facilities on its lands.

ES.1-3 DR&R—Potential Costs

DR&R is basically construction in reverse, with the added cost and complication of restoring the surface of the land to a condition acceptable to the state. Due to the geographic isolation of much of Alaska's oil patch (even the fields on the west side of Cook Inlet pose logistical challenges), construction costs in the state are generally higher than in other oil producing states.

At this time, there is no publically-available estimate of the cost to remove the infrastructure installed on state leases. Producers, as part of their corporate accounting, maintain estimates of their DR&R liabilities, but this information is only available to the public at an aggregate level. Because the state's fields are still very much active, little DR&R work has been conducted in the state, and thus there is little information on actual DR&R costs. In addition, there is no DR&R standard regarding what infrastructure must be removed, what can remain, and what restoration work must be conducted to obtain the satisfaction of the state. Regardless of these unknowns, one thing is known: DR&R in Alaska will not be inexpensive.

ES.1-4 DR&R—Risks to the State

Under ideal circumstances, all producers would adhere perfectly to the terms of their leases during operations, and all DR&R activities would be performed to the satisfaction of the state when production ends. However, as the Pacific Energy bankruptcy in Alaska and similar situations in other states show, circumstances are not always ideal.

If an entity with a DR&R liability ceases to exist (through bankruptcy, partnership dissolution, or other mechanism), the bonds that they have filed with the Department of Natural Resources and the Alaska Oil and Gas Conservation Commission could be used to cover some portion of the DR&R costs associated with the defunct entity's infrastructure. The value of these bonds vary, but are generally not equal to the total costs of DR&R, which could lead to the remaining DR&R costs falling to the state as the landowner.

Bonds and other forms of financial surety are used to help ensure that a party (the lessee or operator) adheres to the terms of a lease or permit or other agreement. Bonds and other forms of financial surety are intended to be penal in nature—if a lessee or operator does not do what it is supposed to do, the bond is forfeited in favor of the land or resource owner.

Several different types of bonds are widely used: an individual bond covers a single activity, and a blanket bond covers numerous activities in a given area (i.e., across a state or in a unit) or all the activities of a single operator.

ES.1-5 DR&R—Mitigating the State's Risk

To mitigate the state's financial exposure to DR&R costs should an operator fail to meet their DR&R responsibilities, and to promote the continued responsible development of the state's oil and gas resources, the state needs to continue attracting investment in the state's oil and gas sector while managing the financial risks associated with the potential DR&R liabilities.

As one step in better understanding how the state can manage its financial exposure, the Alaska Department of Natural Resources has commissioned a review of how other jurisdictions (both domestic and international) strive to attain this balance, and in particular the approaches taken to the bonding of oil and gas and mining operations. Seven domestic jurisdictions (Colorado, California, Pennsylvania, Texas, Wyoming, U.S. Federal onshore lands, and U.S. Federal offshore lands), four international jurisdictions (the United Kingdom, Norway, Russia, and Canada (provinces and the federal government)) and one extra-national entity (the World Bank, as a globally recognized leader in providing guidance to developing nations) were selected for review. The selections are intended to capture jurisdictions that have significant oil and gas or mining industry activity, which indicates a balance between the resource potential and the regulatory regime. The rationale for the selection of these jurisdictions is presented in Table S.1-1.

ES.2 Methodology

This review was conducted utilizing a multi-step methodology as described below:

1. Researchers conducted a keyword-driven Internet search to identify the agency or agencies within each jurisdiction that have bonding authority over oil and gas operations.
2. The websites of the agency or agencies with bonding authority were then reviewed to identify
   a. The statutory authority of each agency
   b. The regulations promulgated by each agency
3. Statutes and regulations were then thoroughly reviewed to identify
   a. The geographical scope of the agency's authority (state lands, private lands, etc.)
   b. The infrastructure and activities for which the agency requires bonding
   c. The amount of bonding required
   d. The types of financial instruments suitable for bonding
   e. Additional guidance or policies used in determining bonding amounts
4. Policies, notices, rules, etc. identified in 3(e) above were obtained and reviewed
5. Agency staff were contacted when necessary to obtain clarification of statutes, regulations, and policies

In addition, a keyword-driven Internet search was conducted to identify studies, papers, reports, and other documentation related to the bonding of oil and gas and mining operations. This search identified reports produced by the General Accounting Office, stakeholder groups, state legislatures, academics, and others. These documents were used to confirm the information gathered and reviewed in Steps 3 and 4 above, and to contribute to the analysis. Additionally, regulatory agency staff were contacted by phone and email when necessary to confirm information.

The methodology was executed by staff with first-hand experience working in the oil and gas and mining sectors in the selected jurisdictions.

Table S.1-1 Summary of Jurisdictions Reviewed

Jurisdiction	Sector	Onshore/Offshore	Rationale
States			
California	Oil and Gas	Onshore State Waters Offshore	Progressive regulatory regime Oil and gas sector transitioning with shale potential; renewed interest in oil and gas-related regulation One of five states with offshore production from state waters
Colorado	Oil and Gas/ Mining	Onshore	Oil and gas sector transitioning with shale potential; renewed interest in oil and gas-related regulation Long history of mining activities; numerous idled/decommissioned mines in state
Pennsylvania	Oil and Gas	Onshore	Long history of oil production Oil and gas sector enjoying renaissance Renewed interest in oil and gas-related regulation
Texas	Oil and Gas	Onshore State Waters Offshore	Mature oil and gas sector On- and offshore production One of five states with offshore production from state waters
Wyoming	Oil and Gas/ Mining	Onshore	Long history of oil production Oil and gas sector enjoying renaissance Renewed interest in oil and gas-related regulation
Nations			
US Federal Government	Oil and Gas/ Mining	Onshore Federal Lands Federal Waters Offshore	Provides useful comparison for foreign jurisdictions
Canada	Oil and Gas/ Mining	Onshore Offshore	Mature oil and gas sector Well-developed regulatory regime
Norway	Oil and Gas	Offshore	Mature oil and gas sector Well-developed regulatory regime Aging infrastructure
UK	Oil and Gas	Offshore	Mature oil and gas sector Well-developed regulatory regime Aging infrastructure
Russia	Oil and Gas /Mining	Onshore Offshore	Long history of oil and gas/mining developments Sector dominated by majors Arctic offshore frontier developments
Extra-National			
World Bank		Onshore Offshore	The World Bank have developed regulations and best practices for nations receiving aid; these regulations and practices are frequently promulgated in developing nations.

ES.3 Domestic Jurisdiction Summaries

This section contains a summary of findings from each of the domestic jurisdictions reviewed. These summaries are followed by a discussion of some of the commonalities and differences identified among the domestic jurisdictions. Table S.3-1 provides details on what infrastructure or activities are bonded in each jurisdiction and the amount of bonding.

Table ES.3-1 Summary of Bonding Across Domestic Jurisdictions

Jurisdiction	Individual Lease Bond Amount	Blanket Lease Bond Amount	Well Bond Amount	Other Bond Amount
Alaska	$100,000[1]	$500,000 (statewide)[1]	$100,000 minimum per well $200,000 (statewide blanket)	—
California	At the discretion of the State	At the discretion of the State	$25-40,000 (onshore single well) $200-2,000,000 (onshore blanket bond) $1,00,000 (offshore blanket bond)	—
Colorado	—	—	$5,000 (single well) $15,000 (for all wells on lease) $25,000 (statewide blanket)	$2-25,000 (surface owner protection statewide) $10-100,000 (well abandonment bond)
Pennsylvania	$25,000 (on State lands)	—	$4,000 (individual well) up to NTE $600,000 (statewide blanket)	$10-100,000 (minimums) per well on State lands
Texas	—	—	Blanket amount: $25-250,000 Offshore wells: Additional $60-100,000 blanket bond	—
Wyoming	—	$100,000 (statewide)	$10-20,000 (single well) $5,000 (statewide blanket)	Idle well bond: $10/foot
US Federal Onshore, BLM	NLT $10,000	NLT $25,000 (statewide) NLT $150,000 (nationwide)	—	NLT $1,000 (surface owner protection bond)
US Federal Onshore, National Park Service	—	—	—	NTE $50,000 per operation NTE $200,000 per unit
US Federal Onshore, USFWS	—	—	—	Full cost of restoration of damaged areas
US Federal Offshore, Leasehold	$50,000	$300,000 (areawide)	—	—

Table ES.3-1 Summary of Bonding Across Domestic Jurisdictions

Jurisdiction	Individual Lease Bond Amount	Blanket Lease Bond Amount	Well Bond Amount	Other Bond Amount
US Federal Offshore, Exploration	$200,000	$1,000,000 (areawide)	—	—
US Federal Offshore, Development/ Production	$500,000	$3,000,000 (areawide)	—	—
US Federal Offshore, Right-of-Use/Easement	—	$500,000	—	—
US Federal Offshore, Pipeline Right-of-Way	—	$300,000	—	—

Notes

1 When assets are proposed to be transferred, the State of Alaska Division of Oil and Gas conducts an assessment of the financial strength of the entity to which the assets would be transferred. The State of Alaska is the only state that has a formalized process to evaluate the financial strength of the transferee in an asset transfer. Depending on the results of this assessment, the Division may require that additional bonding amounts or other financial assurances be provided as a condition of the asset transfer.

ES.3-1 California

Bonds are required by two entities: the State Lands Commission (SLC) can require bonds for activities on state lands; the Division of Oil, Gas, and Geothermal Resources (DOGGR) requires bonds for wells.

The SLC has wide latitude in determining bonding amounts for activities on state leases—there are no minimum or maximum bonding amounts contained in regulation—as well as when and by how much bonding amounts may be increased. The SLC uses estimates of DR&R costs generated by BOEM when evaluating the sufficiency of current bond amounts for offshore infrastructure; the SLC has raised bond amounts when platforms and offshore islands have been sold/transferred.

The Division of Oil, Gas, and Geothermal Resources requires that active and idle wells be bonded, and has the power to require "end-of-life" bonds for wells and other infrastructure. DOGGR has the power to adjust bonding amounts frequently, although well bond amounts have only been changed twice since 1999. Offshore operators must post a bond in an amount sufficient to cover the full costs of P&A of all the operator's wells.

ES.3-2 Colorado

Bonds are required by two entities: the State Board of Land Commissioners (SLB) can require bonds for activities on state lands; the Colorado Oil and Gas Conservation Commission (COGCC) requires bonds for wells.

The SLB requires a reclamation bonds for all wells on state lands. The reclamation bonds range in value from $5,000 for a single well to a $25,000 blanket bond for all wells drilled on state lands. The COGCC requires a number of different bonds, including surface protection bonds (to provide a financial assurance for the surface owner that lands will be restored after production ceases) and soil protection, plugging, and abandonment bonds (to ensure that wells are properly decommissioned and the surface rehabilitated).

The state also maintains an Oil and Gas Conservation and Environmental Response Fund to perform DR&R activities on abandoned sites.

ES.3-3 Pennsylvania

Bonds are required by two entities: the Department of Conservation and Natural Resources (for operations on state forest lands) and the Department of Environmental Protection (PADEP, for wells drilled anywhere in the state).

The Department of Environmental Protection requires that bonds be filed prior to a well being drilled; the bond amounts vary with the depth of the well. For shallow wells, bond amounts range from $4,000 (for a single well) to a statewide blanket bond not to exceed $250,000. For deep wells, bond amounts range from $10,000 (for a single well) to a statewide blanket bond not to exceed $60,000. The bond amounts can be updated every two years.

The Department of Conservation and Natural Resources requires bonds for activities on state lands. A lease bond in the amount of $25,000 is required, as is a well plugging security bond. The minimum value of the well plugging security bond varies with depth, from $10,000 to $100,000 per well. Bond amounts can be increased every five years.

The Department of Environmental Protection also maintains an orphan well DR&R fund, which is funded by a $100 surcharge on oil wells and a $200 surcharge on natural gas wells.

ES.3-4 Texas

The Texas Railroad Commission (RRC) oversees oil and gas operations on state and private lands, and in state waters. There are no surface or lease bonds required in Texas; only wells are bonded. The bonding amount for wells varies considerably—for a single well, an operator could post a bond of only $2/foot. For operators with multiple wells, blanket bond amounts range from $25,000 for 10 or fewer wells up to $250,000 for operators with more than 100 wells.

Additionally, a bond ranging from $60,000 to $100,000 must be posted for each idle well that is located offshore. These additional bonds may be reduced depending upon a range of factors, including a valuation of the operator’s net worth.

The State maintains an Oil Field Cleanup Fund, which is funded primarily by a $100 to $200-per well drilling permit fee, as well as a regulatory fee on each barrel of oil and thousand cubic feet of natural gas produced.

ES.3-5 Wyoming

Two agencies require bonds for oil and gas operations: the Office of State Lands and Investments requires bonds for activities on state lands, and the Wyoming Oil and Gas Conservation Commission (WOGCC) requires bonds for active wells, idle wells, and for surface protection in the case of a split estate.

There is no individual lease bond amount set in regulation; rather, regulation states that the amount "shall be set in an amount…sufficient to protect and indemnify the State of Wyoming." However, in lieu of an individual lease bond, a lessee can file a blanket bond in an amount of not less than $100,000.

Well-specific bonding amounts range from $10 -20,000 for a single active well, up to a blanket bond amount of $75,000 for all of an operator's active wells. In addition, the Commission requires that operators provide bonds for their idle wells in the amount of $10/foot; this amount can be increased no more frequently than every three years.

In split estate cases (where the surface owner is different from the mineral rights owner), the WOGCC may require a surface access bond of not less than $10,000 per well site. This bond is only required if the operator and surface owner cannot otherwise come to terms regarding access.

ES.3-6 Federal Offshore

The Bureau of Ocean Energy Management requires that lessees provide bonds or other financial securities in amounts that vary with the activity on a lease, as shown in Table S3-1. This approach matches, to some extent, the amount of the bond with the potential financial risk to the government—as more infrastructure is installed, the bonding amount increases. In addition, BOEM may require supplemental financial security of an operator dependent upon its financial stability, past experience, and record of compliance. However, if one record title owner meets certain financial strength and reliability criteria, then supplemental financial security is not required.

As of the time of this writing, BOEM is soliciting public comment regarding proposed changes to its bonding and financial assurance regulations.

ES.3-7 Federal Onshore

The surface ownership of federal lands is divided among the Bureau of Land Management (BLM), United States Fish and Wildlife Service (USFWS), National Park

Service (NPS), and United States Forest Service (USFS), among others. Federally-owned subsurface minerals (including oil and gas) are managed by the BLM.

The BLM requires lessees to post either an individual lease bond (in an amount not less than $10,000), a statewide lease bond (in an amount not less than $25,000), a nationwide lease bond (in an amount not less than $150,000), or a unit operator's bond in an amount to be determined by BLM. In addition to these bonds, in the case of a split estate, the BLM may require an operator to post a bond with a minimum amount of $1,000 to ensure the surface estate is reclaimed appropriately. The BLM can increase these bond amounts at any time; however, the lease bond amounts have not been increased since 1960.

As the managers of the federal surface estate, the USFWS, NPS, and USFS may require bonding in addition to that required by the BLM. There is no bonding amount in regulation for USFS or USFWS-managed lands; NPS regulations cap the amount of an additional bond at $200,000.

ES.4 Domestic Jurisdictions—Commonalities

Review of the approaches taken by the domestic jurisdictions to the bonding of oil and gas operations have resulted in the identification of several areas of commonality. These are discussed below.

Bonded amounts are losing value in real terms due to inflation and due to rising DR&R costs as driven by environmental regulation. In many of the domestic jurisdictions reviewed, bonding amounts have not been increased for years or in some cases for decades. On Federal lands, the bond minimum for individual bonds was last set in 1960, and the bond minimums for statewide bonds and for nationwide bonds were last set in 1951 (GAO 2011). In Pennsylvania, despite statutory provisions that empower the Environmental Quality Board to adjust the level of bonding to match projected reclamation costs every two years, bonding amounts have not been increased since 1984 (Mitchell and Casman 2011). In Wyoming, bond amounts for wells were last adjusted in 2000. And in California, regulators established new bonding amounts in 2014; the last adjustment to bonding amounts was made in 1999. As a result, due to inflation, the current value of the bonds is less than when they were originally set in place.

Also, in the intervening period, the infrastructure and practices of operators have changed considerably—in areas where relatively shallow, vertical wells with small surface footprints were the norm, we now see deep, horizontal wells with multiple completions and a much larger surface footprint. Compounding the issue, environmental regulations and standards have changed over time as well, and continue to change. These two changes have resulted in increased DR&R costs, which have generally not been reflected in bonding amounts.

The infrastructure and activities that are bonded varies across jurisdictions. Jurisdictions require bonds for differing activities and different infrastructure. In all state jurisdictions reviewed, an oil and gas conservation commission or other regulatory agency requires a bond prior to the drilling or modification of a well—these bonds are intended to help ensure that the well will be properly plugged and abandoned at the end-of-life.

Other bonds may be required in addition to a well bond. Lease bonds, which are generally required by a state or federal agency when state or federal lands are leased for exploration or production, are “intended to help ensure compliance with all the lease terms including protection of the environment.” (Fulton 2002). In Wyoming and Colorado, an operator may be required to post a surface use bond if an operator and a surface owner cannot reach an agreement regarding use of the surface without the intervention of the state; these bonds are intended to ensure appropriate reclamation of the surface at the end of operations. Conversely, in Pennsylvania, the Oil and Gas Act prohibits private landowners from securing financial assurances from the operator independent of Pennsylvania regulations (Mitchell and Casman 2011).

In most jurisdictions, bonding amounts are not directly tied to real-world DR&R costs, and the aggregate value of bonds is less than potential DR&R costs. Few domestic jurisdictions base their bonding amounts on real-world DR&R costs. In California, bond amounts for offshore infrastructure have been increased in recent years in recognition of the DR&R costs associated with platform removal. The Bureau of Ocean Energy Management (BOEM) can require operators to file a supplemental bond to account for DR&R costs, and the Bureau of Land Management (BLM) may require bonding amounts up to the estimated cost of plugging a well and performing reclamation.

The gap between actual (or potential/projected) end-of-life/DR&R costs and bonding amounts varies widely and is dependent upon, among others, the type of the infrastructure, surface ownership and preferred future use, ease of access/location, and the bonded amount (if any):

- A General Accounting Office report published in 2010 (and using 2008 data) estimated an average reclamation cost of $12,788 per well, with 88,537 wells on Federal land, equating to a potential DR&R liability of $1.132 billion (GAO 2010). At that time, the operators of those wells had posted only $162 million in personal and surety bonds, or just slightly more than 10 percent of the value of the potential liability.
- Plugging a 3,000 foot-deep abandoned well and restoring the site in western Pennsylvania is estimated to cost approximately $60,000; the bonding amount for such a well could be as little as $2,500 (Mitchell and Casman 2011).
- A review of the costs to plug abandoned wells and reclaim the sites in Wyoming revealed the actual cost of plugging and reclamation to be approximately $29,000 per well (or $10.81 per foot of well depth), while the bond amount per well was approximately $6,000 (or $1.79 per foot) (Andersen and Coupal 2009).

Lessee/operator finances are generally not factored into determining bonding amounts. None of the reviewed domestic jurisdictions have in their regulations or guidance a requirement that an operator's or lessee's financial condition be considered when determining bonding amounts (i.e., that bonding amounts be increased for operators with less financial strength than other operators).[1]

Regulatory agencies do review the financial conditions of lessees and operators: California Division of Lands staff indicated that they review publically-available financial data of operators and lessees as part of their due diligence when deciding on the approval of lease assignments, and BOEM does consider the financial strength of an operator when determining if a supplemental bond is required. However, in no jurisdiction is such information used in determining an actual bonding amount.

Regulators accept only a few types of financial security instruments to meet bonding requirements. Surety bonds and cash (or cash equivalents like Treasury bonds) are the preferred instruments of all domestic jurisdictions reviewed, but other instruments may be employed: BOEM and BLM, for example, may accept a third-party guarantee in some cases, and may authorize trust-type accounts for specific purposes, including funding end-of-life DR&R activities. Regulators in most of the reviewed jurisdictions have in regulation a considerable degree of latitude in determining what constitutes an acceptable financial security; this regulatory latitude may provide for the use of innovative approaches to bonding.

DR&R liability issues are being delayed. High prices and demand for oil and natural gas is resulting in many marginal wells being kept in operation at the present time. In addition, regulations in some jurisdictions allow operators to cease production from wells but to place them into an inactive or idled state for extended periods of time—in Pennsylvania, for example, wells can be kept "inactive" for years. Both of these situations are effectively delaying the retirement timeframe for infrastructure, and also the time at which DR&R costs will be realized.

1 Note that an operator's cost for obtaining a surety bond is tied in part to the operator's financial strength and condition; all other considerations being equal, a financially sound operator would generally pay a lower premium than an operator with lesser financial resources.

ES.5 Summary of Findings: International Jurisdictions and the World Bank

Review of the approaches taken by international jurisdictions and the World Bank to the bonding of oil and gas (and in some cases mining) operations have resulted in the identification of several areas of commonality:

ES.5-1 Introduction

The international summary report synthesizes the results of the review undertaken for Canada, the United Kingdom (UK), Russia, Norway, Brazil and the World Bank. These countries were chosen given their oil and gas and mining resources and the maturity of their regulatory system. The World Bank was chosen as representative of requirements for internationally funded projects within developing countries. Each country's regulations and requirements are a product of their political, legal and economic systems influenced by their history with the decommissioning and abandonment of oil wells and mine sites. In the following sections we provide a summary of the regulations and financial assurances governing Decommissioning, Removal and Restoration in each jurisdiction.

ES.5-2 Summary of International DR&R Regulations

The international approach to DR&R varies by country; oil, gas, and mining exploration; and production maturity. The UK, Brazil, and Russia have well developed regulatory regimes which require DR&R plans to be developed in advance of the start of production and in some cases during the environmental approval process for exploration and production activities. Canada has a complex regulatory regime involving management and regulation by both the federal and provincial/territorial governments depending on the resource in question and its location. DR&R plans are required and sometimes impact assessments of the plans are also required. Norway also has a complex regulatory regime requiring the development of DR&R plans and associated impact assessments of the plans 2-5 years prior to license expiration or cessation of operations. While each of these countries may require development of DR&R plans as part of the environmental regulatory approval process, the approach to ensuring they are implemented and funded varies.

Russia requires companies to prepare DR&R plans during the environmental and project approval process. In addition, submittal of a closure plan is required for approval 1 year prior to the termination of mining or oil and gas production. The implementation of the closure plan is at the company cost. Further, Russia implements a ‘pay to pollute’ program for payment of waste, air quality, and soil impacts as impacts occur to ensure collection of financial compensation in advance of facility closure. Russia imposes civil and criminal liability on companies and individual employees of companies if the closure of the mining or oil and gas production facilities are not executed as agreed in the closure plan.

In the UK, development of an abandonment program containing an overall cost estimate of the preferred decommissioning option and the basis on which the estimate is made is required, is subject to approval or rejection (with or without modification), and is either subject to conditions or accepted unconditionally. To ensure a streamlined process, a fill-in-the-blank template is provided for development of an abandonment program. The UK regulations provide for multiple measures to ensure that companies potentially liable for decommissioning costs have the financial capability to meet obligations. The regulations allow for the inclusion of current and past operators, current and past license holders, parties to a joint operating agreement, those who have a financial interest in the infrastructure, and the parent companies of these organizations. In short, any party entitled to derive a financial or other benefit from the infrastructure may be held liable. Review of published decommissioning plans documented that the UK is identifying current and past operators, current and past license holders, parties to joint operating agreements, parties with financial interest and parent companies to be held liable for DR&R.

Brazil contractual provisions included in concession agreements include decommissioning obligations and liabilities, technical requirements for abandonment procedures, and surrender of acreage. The concession agreement also provides that the company’s obligation to perform the operations necessary to inactivate and abandon a field, at its own cost and risk, are not waived when the inactivation and abandonment guarantee is presented. Regulations require the development of mine closure and oil well abandonment plans. These plans must include actions for remediation, reforestation, decontamination and removal of facilities, and other necessary measures to abandon the area, in compliance with the corresponding timetable, described in the associated Environmental Impact Assessment. In cases where there is non-compliance with mine closure and oil well abandonment, sanctions can be applied ranging from a fine to the termination of the license or concession agreement.

There are several regulatory jurisdictions within Canada, including the federal government, the 10 provincial governments, the three territorial governments, and aboriginal government organizations. The federal government retains jurisdiction over Crown (federal) lands, the offshore areas of Canada, the Territory of Nunavut, and mining activities involving uranium or other nuclear elements. The federal government also works with aboriginal government organizations in a co-management capacity to manage mineral and petroleum resources on aboriginal lands. During the permitting phase of a project, resource developers are required to provide a dismantlement, removal, and reclamation (DR&R) plan and demonstrate financially that it is capable of implementing the proposed project. The regulatory agency must approve the DR&R plan prior to granting approval to operate a mine, well site, or petroleum production site. The requirement that resource developers prepare a DR&R plan and demonstrate financial responsibility to address future liabilities was universal among the various jurisdictions in Canada; however, the methods used for determining the amount of security required for a given mine or oil and gas operation varied widely; not only among jurisdictions, but often by resource sector within a given jurisdiction. For some types of mines and activities, DR&R plans will need to be updated and resubmitted prior to the cessation of activities. An impact assessment may be associated with the submission of a DR&R plan at this time.

In Norway and in accordance with the Petroleum Act, a licensee shall submit a decommissioning plan 2 to 5 years before the license expires or is relinquished, or before facility operation ceases. The decommissioning plan must be submitted to the Royal Ministry of Petroleum and Energy (the Ministry). Disposal may include further use of a platform in petroleum activities, other uses, complete or partial removal, or abandonment. Notification to the Ministry other than the decommissioning plan is necessary when the use of the facility is expected to terminate permanently before the expiration of the license. The decommissioning plan has two main parts—a disposal section and an impact assessment. The first part discusses a disposal plan for shutdown of production and disposal of production facilities. The impact assessment submitted with the decommissioning plan should give a short account of the relevant disposal alternatives, the envisaged effects of those disposal methods to the environment and other commercial activities, and documentation of activities. In addition to the Act, the Oslo Paris Convention for the Protection of the Marine Environment of the NorthEast Atlantic (OSPAR Convention) also governs disposal of facilities. Under this Convention, only a small number of facilities can be abandoned on site. A disposal decision will be made on the basis of the impact assessment, the consultation opinions, the disposal section, and evaluations of the proposed disposal plan.

Since early 2009, the World Bank has been leading an initiative called "Toward Sustainable Decommissioning of Oil Fields and Mines Initiative" to assist international governments in oil and gas and/or mining resource-rich developing countries in the process of undertaking earlier, more systematic, comprehensive, and responsive planning of the decommissioning and closure phase of mining and oil and gas production operations. The World Bank was included in this review, as many developing countries are using the guidance provided by the World Bank through a toolkit ("Toward Sustainable Decommissioning of Oil Fields and Mines: A Toolkit to Assist Government Agencies") covering the essential economic, social, environmental, regulatory, and technical aspects of decommissioning to develop their regulations.

ES.5-3 Summary of DR&R Financial Assurances

The international approach to DR&R financial assurances also varies by country; oil, gas, and mining exploration; and production maturity. All jurisdictions reviewed require developers to show some measure of financial capability with respect to DR&R plans but how that is calculated and what those financial assurance look like varies between jurisdictions.

The following table summarizes how each of the jurisdictions reviewed determines the value of financial assurances and, where applicable, what types of securities are acceptable. For complex jurisdictions where there is significant variation of approaches at the provincial or state level, summary statements have been made.

Table ES.5-1 Summary of International Jurisdiction DR&R Regulations

Jurisdiction	Determination of Financial Assurances	Types of Securities
Brazil	Concessionaires (developers) agree to pay all costs of abandonment and decommissioning and must issue a guarantee regarding abandonment operations	No identified securities
Canada	The methods used for determining the amount of security required for a given mine or oil and gas operation vary widely; not only amongst jurisdictions but by resource sector within a given jurisdiction. The value of securities may be based on detailed cost estimates, security	Most provinces require hard forms of financial assurance such as cash, cheques, irrevocable letters of credit, provincial bonds and third party securities. Manitoba and Ontario accept soft forms of financial security

Table ES.5-1 Summary of International Jurisdiction DR&R Regulations

Jurisdiction	Determination of Financial Assurances	Types of Securities
	deposits related to size of operation or by comparing the ratio of assets to liabilities.	as well such as corporate financial tests to meet credit ratings.
Norway	Regulation stipulates that the licensees are liable for willful or negligent damage, harm, or inconvenience in relation to the abandoned facility. The licensees and the State can agree that future maintenance and responsibilities will be transferred to the State for an agreed upon financial compensation.	No identified securities
Russia	Developer must provide for liquidation and conservation of operations in the field at their cost.	No identified securities
United Kingdom	Financial securities should provide at least 100 percent of the estimated costs of removal including site clean-up and many require the addition of 50 percent of the estimated costs to cover uncertainties.	Acceptable forms of payment include cash, irrevocable standby letters of credit issued by a Prime Bank, or on –demand performance bonds
World Bank	Not Applicable – Guideline provides steps to identify Financial Assurances	Not Applicable – Guideline provides steps to identify Securities

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Decommissioning, Removal, and Restoration Regulatory Review

Federal Jurisdictional Areas—Onshore and Offshore

State Jurisdictions—California, Colorado, Pennsylvania, Texas, and Wyoming

November 2014

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State Jurisdictions—California, Colorado, Pennsylvania, Texas, Wyoming

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Tables

Acronyms and Abbreviations

Federal Jurisdictional Areas-Onshore

APD	Application for Permit to Drill
BLM	Bureau of Land Management
CFR	Code of Federal Regulations
GAO	Government Accounting Office
MOU	Memorandum of Understanding
NFS	National Forest Service
NPS	National Park Service
SUP	Special Use Permit
SUPO	Surface Use Plan of Operation
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service

Federal Jurisdictional Areas-Offshore

ANPR	Advance Notice of Proposed Rulemaking
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
COP	Construction and Operations Plan
CPI-U	Consumer Price Index-All Urban Consumers
NEPA	National Environmental Policy Act
NTLs	Notices to Lessees and Operators
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OFCU	Oil Field Cleanup
ROWs	Rights-of-Way
RUEs	Rights-of-Use and Easements

SAP	Site Assessment Plan
SLA	Submerged Lands Act
Treasury	U.S. Department of the Treasury

California

Cal Code Regs	California Code of Regulations
Cal Pub Res. Code	California Public Resources Code
DOGGR	Division of Oil, Gas, and Geothermal Resources
DR&R	Decommissioning, Removal, and Restoration
MMS	Minerals Management Service
SLC	State Lands Commission

Colorado

BLM	U.S. Bureau of Land Management
CCR	Code of Colorado Regulations
COGCC	Colorado Oil and Gas Conservation Commission
C.R.S.	Colorado Revised Statutes
DRMS	Division of Reclamation, Mining and Safety
E&P	Exploration and Production
OGC Act	Oil and Gas Conservation Act
PDPA	Colorado Public Protection Act
SLB	State Land Board
USEIA	United States Energy Information Administration

Pennsylvania

DCNR	Pennsylvania Department of Conservation and Natural Resources
OOGM	Office of Oil and Gas Management, Pennsylvania Department Environmental Protection
Pa.C.S.	Pennsylvania Consolidated Statutes

PADEP	Pennsylvania Department of Environmental Protection
PUC	Pennsylvania Public Utility Commission

Texas

OFCU	Oil Field Cleanup
RRC	Railroad Commission of Texas
TAC	Texas Administrative Code
TGLO	Texas General Land Office

Wyoming

BLC	Board of Land Commissioners
CD	certificate of deposit
DEQ	Wyoming Department of Environmental Quality
EIA	U.S. Energy Information Administration
LQD	Land Quality Division
OSLI	Office of State Lands and Investments
PRB	Powder River Basin
WMA	Wyoming Mining Association
WOGCC	Wyoming Oil and Gas Conservation Commission
W.S.	Wyoming Statutes

FEDERAL JURISDICTIONAL AREAS—ONSHORE

1. Background and History

The U.S. Department of the Interior's Bureau of Land Management (BLM) and the Department of Agriculture's U.S. Forest Service (USFS) both lease lands for hydrocarbon production, and oversee oil and gas operations on lands under their respective management. The National Park Service (NPS) oversees oil and gas operations on park lands where the mineral resource is not owned by the federal government. The United States Fish and Wildlife Service (USFWS) permits and oversees oil and gas operations on wildlife refuges.

2. Regulatory Structure

2.1 Bureau of Land Management

The BLM's mission is to sustain the health, diversity, and productivity of the public lands for the use and enjoyment of present and future generations. The BLM is the largest federal land manager, overseeing more than 247 million acres, and is responsible for onshore subsurface mineral estate development on 700 million acres[1] of publicly owned federal lands (BLM 2014a).

The BLM Oil and Gas Management program oversees more than 47,000 leases, covering 36 million acres across 40 states (BLM 2013). The 63,000 wells on these leases account for 11 percent of the Nation's natural gas supply and 5 percent of its oil (BLM 2014a).

BLM leases are held by a range of oil and gas companies, from major international integrated oil companies to very small independent operators. BLM is responsible for leasing federal surface and subsurface lands, for ensuring compliance with lease terms, and for monitoring the environmental performance of lessees.

2.2 U.S. Forest Service

The USFS and BLM work cooperatively in the development and oversight of oil and gas activities on USFS lands. In essence, USFS lands are "split estate," in that BLM manages (on behalf of the United States) the mineral rights under USFS lands, and the USFS manages (on behalf of the United States) the surface lands within its jurisdiction.[2] The USFS Minerals and Geology Management program manages energy and

---

1 A range of other federal agencies play a role in oversight of onshore oil and gas infrastructure, including the Federal Energy Regulatory Commission, the Pipeline and Hazardous Materials Safety Administration, and others. Review of statutes, regulations, and guidance has not indicated that these other agencies are not directly involved in the bonding of such infrastructure.

2 In split estate situations, the surface rights and subsurface rights (such as the rights to develop minerals) for a piece of land are owned by different parties. In these situations, mineral rights are considered the dominant estate, meaning they take precedence over other rights associated with the property, including those associated with owning the surface. However, the mineral owner must show due regard for the interests of the surface estate owner and occupy only those portions of the surface that are reasonably necessary to develop the mineral estate.

mineral resources development. More than 5 million acres of USFS surface lands are leased for mineral extraction (USFS 2012).

Per BLM Memorandum of Understanding (MOU) WO300-2006-07/Forest Service Agreement No. 06-SU-11132428-052, the Forest Service role in oil and gas leasing on USFS lands is as follows:

> "For leases and oil and gas operations on NFS [National Forest Service] lands, the Forest Service cooperates with the BLM to ensure that management goals and objectives for oil and gas exploration and development activities are achieved, that operations are conducted to minimize effects on natural resources, and that the land affected by operations is reclaimed. The Forest Service must authorize the BLM to offer specific lands for lease before the BLM can issue leases on those lands.
>
> Once a Federal lease is issued on NFS lands, the Forest Service has the full responsibility and authority to approve and regulate all surface-disturbing activities associated with oil and gas exploration and development through analysis and approval of the SUPO [Surface Use Plan of Operation] component of an APD [Application for Permit to Drill]." (BLM and USFS 2006)

2.3 National Park Service

The NPS oversees the development of private (non-federal) oil and gas resources that underlie NPS lands, and oversees the production of minerals from NPS lands. The NPS promulgated regulations at 36 Code of Federal Regulations (CFR) Part 9, Subpart B, that "control all activities within any unit of the National Park System in the exercise of rights to oil and gas not owned by the United States where access is on, across or through federally owned or controlled lands or waters." (36 CFR 9.30) The 9B regulations require prospective operators to obtain NPS approval of their plans of operations and to secure reclamation bonds before they commence operations in a unit. Where the oil and gas resources are owned by the United States, BLM regulations at 43 CFR 3100 et. seq. are applied.

The 9B regulations have not changed substantively since their promulgation more than 30 years ago. In 2010, the NPS began a rulemaking effort to improve the overall effectiveness of the regulations, including updating the process for bonding operations. This rulemaking stalled, and to date the regulations have not been changed.

2.4 U.S. Fish and Wildlife Service

The USFWS permits and oversees the development of private (non-federal) oil and gas resources that underlie national wildlife refuges; where the oil and gas rights are owned by the United States, BLM regulations at 43 CFR 3100 et. seq. are applied.

3. Bonding/Financial Commitments

Both the BLM and USFS may require operators to place bonds or other financial surety measures prior to performing work on a lease. The bonding/financial surety regulations of each agency are discussed below.

3.1 Bonding, Oil and Gas Operations, Bureau of Land Management

BLM regulations related to oil and gas leasing are found generally at Title 43—Public Lands: Interior, Subtitle B, Chapter II—Bureau of Land Management, Department of the Interior of the CFR. Specifically, regulations related to the bonding of oil and gas infrastructure are found at 43 CFR 3104, Bonds.

Prior to starting any surface-disturbing activities, the lessee, sub-lessee, or operator of an oil and gas lease is required to submit a surety bond or a personal bond (43 CFR 3104.1, Bond obligations). The bond is required to ensure "complete and timely plugging of the well(s), reclamation of the lease area(s), and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations on the lease(s)…"

3.1.1 Bond Types and Bonding Amounts

Four categories of bonds are available: an individual lease bond, a statewide bond, a nationwide bond, and a unit operator's bond. Details of these are as follows:

- Lease bond. "A lease bond may be posted by a lessee, owner of operating rights (sub-lessee), or operator in an amount of not less than $10,000 for each lease conditioned upon compliance with all of the terms of the lease." (43 CFR 3104.2, Lease bond)
- Statewide bond. "In lieu of lease bonds, lessees, owners of operating rights (sub-lessees), or operators may furnish a bond in an amount of not less than $25,000 covering all leases and operations in any one State." (43 CFR 3104.3, Statewide and nationwide bonds, subpart (a))
- Nationwide bond. "In lieu of lease bonds or statewide bonds, lessees, owners of operating rights (sub-lessees), or operators may furnish a bond in an amount of not less than $150,000 covering all leases and operations nationwide." (43 CFR 3104.3, Statewide and nationwide bonds, subpart (b))
- Unit operator's bond. "In lieu of individual lease, statewide, or nationwide bonds for operations conducted on leases committed to an approved unit agreement, the unit operator may furnish a unit operator bond in the manner set forth in Sec. 3104.1 of this title. The amount of such a bond shall be determined by the authorized officer. The format for such a surety bond is set forth in Sec. 3186.2 of this title. Where a unit operator is covered by a nationwide or statewide bond, coverage for such a unit may be provided by a rider to such bond specifically covering the unit and increasing the bond in such amount as may be determined appropriate by the authorized officer." (43 CFR 3104.4, Unit operator's bond)

These bond amounts have not changed in decades. The individual bond floor amount was established in 1960, and the bond floor amounts for statewide and nationwide bonds were established in 1951 (GAO 2010).

In addition to the above-listed bonds, on split estate lands, BLM may require a lessee, sub-lessee, or operator to file a "Bond for Surface Owner Protection" with the BLM per 43 CFR 3814.1, Mineral reservation in entry and patent; mining and removal of reserved deposits; bonds, subpart (a). This bond is required only if a lessee, sub-lessee, or operator of an oil or gas lease cannot independently negotiate acceptable terms for access with the surface estate owner. The minimum amount of such a bond is $1,000, but the amount can be set at the discretion of the BLM to take into account surface estate uses and potential damages. The bond must be posted in the form of a corporate surety bond. Gaining access to the surface estate in this manner is a "very rare occurrence" (BLM 2006).

3.1.1.1 Setting and Adjusting Bonding Amounts

BLM has significant discretion in the setting of bond amounts. The regulations at 43 CFR 3104 establish bonding amount floors, but do not establish ceiling amounts except in cases where the lessee or operator presents an unusual risk. In those cases, the bond amount cannot exceed "the total of the estimated costs of plugging and reclamation" in addition to any other amounts owed to the government (e.g., royalties, fines). The actual amount of a lease, statewide, nationwide, or unit operator's bond can be decided by the BLM office that issues the lease. There is no nationwide guidance or process for establishing a bond amount.

The BLM has also provided in regulation a number of means for increasing the amount of a bond including:

- Prior to approving an Application for Permit to Drill. If BLM has demanded from an operator payment under a previous bond or other financial guarantee, BLM may require that operator to post a bond "in an amount equal to the costs as estimated by the authorized officer of plugging the well and reclaiming the disturbed area involved in the proposed operation, or in the minimum amount as prescribed in this subpart, whichever is greater." (43 CFR 3104.5, Increased amount of bonds, subpart (a))
- During Operation. After a lease is issued and drilling or production has begun, BLM may "…require an increase in the amount of any bond whenever it is determined that the operator poses a risk due to factors, including, but not limited to, a history of previous violations, a notice from the Service that there are uncollected royalties due, or the total cost of plugging existing wells and reclaiming lands exceeds the present bond amount based on the estimates determined by the authorized officer." (43 CFR 3104.5, Increased amount of bonds, subpart (b))

- During transfer of lease. If a lease transferee has previously posted a statewide or nationwide bond, the transferee is not required to obtain an individual lease bond, but BLM may increase the amount of the statewide or nationwide bond (43 CFR 3106.6-2, Statewide/nationwide bond)

BLM also has “indirect” means at its disposal to modify the amount of bonds. For instance, a lease or operating rights cannot be assigned if BLM determines that the bond covering activities on that lease is “insufficient.” (43 CFR 3106.7-1, Failure to qualify)

3.1.2 Acceptable Financial Securities

The types of financial securities that are acceptable to meet the bond obligations of a lessee, sub-lessee, or operator of an oil and gas lease include the following:

- Surety bonds issued by qualified surety companies approved by the Department of the Treasury
- Personal bonds, which may include:
  - A certificate of deposit issued by a financial institution
  - A cashier's check
  - A certified check
  - Negotiable Treasury securities of the United States
  - Irrevocable letter of credit issued by a financial institution

3.1.3 Assignation of Leases

The assignation of a federal onshore lease does not diminish the liability of a lessee, sub-lessee, or operator of liability for decommissioning. Per 43 CFR 3106.7, Approval of transfer, a transferee continues “to be responsible for lease obligations that accrued before the approval date, whether or not they were identified at the time of the assignment or transfer [including] responsibility for plugging wells and abandoning facilities, drilled, installed, or used before the effective date of the assignment or transfer.”

This results in overlapping liability, as a person who acquires a federal lease or acquires operating rights to a federal lease assumes “the responsibility to plug and abandon all wells which are no longer capable of producing, reclaim the lease site, and remedy all environmental problems in existence.” This may also result in a situation where multiple bonds are in place for a single lease or piece of infrastructure. The acquirer “must also maintain an adequate bond to ensure performance of these responsibilities” per 43 CFR 3106.7-6, but there is nothing in regulation that prevents BLM from requiring that a bond be maintained for a lease that has been assigned. In fact, 43 CFR 3104.8, Termination of period of liability, states that BLM “shall not give consent to termination of the period of liability of any bond unless an acceptable replacement bond has been filed or until all the terms and conditions of the lease have been met.” The last phrase (“all the terms and conditions of the lease have been met") leaves the door open for BLM requiring that bonds remain in place after assignation.

3.2 Bonding, Oil and Gas Operations, U.S. Forest Service

USFS regulations related to oil and gas leasing are found generally at CFR Title 36—Parks, Forests, and Public Property, Part 228—Minerals, Subpart E, Oil and Gas Resources.

The basis for USFS bonding of oil and gas activities is found in 36 CFR 228.108, Surface use requirements, (g) Reclamation, which states in part:

> "(1) Unless otherwise provided in an approved surface use plan of operations, the operator shall conduct reclamation concurrently with other operations.
>
> (2) Within 1 year of completion of operations on a portion of the area of operation, the operator must reclaim that portion, unless a different period of time is approved in writing by the authorized Forest officer.
>
> (3) The operator must:
>
> (i) Control soil erosion and landslides;
>
> (ii) Control water runoff;
>
> (iii) Remove, or control, solid wastes, toxic substances, and hazardous substances;
>
> (iv) Reshape and revegetate disturbed areas;
>
> (v) Remove structures, improvements, facilities and equipment, unless otherwise authorized; and
>
> (vi) Take such other reclamation measures as specified in the approved surface use plan of operations."

As contained in the MOU between BLM and the USFS concerning oil and gas leasing and operations, the BLM leads much of the oil and gas leasing/operations process on federal onshore lands. The supporting role of the USFS on leasing of Forest Service lands is captured in 36 CFR 228.109, Bonds, which states in part:

> "If at any time prior to or during the conduct of operations, the authorized Forest officer determines the financial instrument held by the Bureau of Land Management is not adequate to ensure complete and timely reclamation and restoration, the authorized Forest officer shall give the operator the option of either increasing the financial instrument held by the Bureau of Land Management or filing a separate instrument with the Forest Service in the amount deemed adequate by the authorized Forest officer to ensure reclamation and restoration."

Therefore, the USFS may require an operator to post a bond in an amount additional to that required by the BLM if, in the opinion of the USFS, the BLM bond is insufficient to cover the expected reclamation and restoration costs. There is no Service-wide guidance on how reclamation and restoration costs are to be determined.

3.2.1 USFS, Oil and Gas, Acceptable Financial Securities

The type of financial security acceptable under 36 CFR 228.109, Bonds, is not defined in USFS regulations.

3.3 Bonding, Oil and Gas Operations, National Park Service

NPS regulations that govern its oversight of oil and gas operations on park lands are found generally at CFR Title 36—Parks, Forests, and Public Property. Specifically, regulations related to the bonding of oil and gas operations are found at 36 CFR 9, Minerals Management, Subpart B—Non-Federal Oil and Gas Rights.

Per 36 CFR 9.32(a) and (b), “no access on, across or through lands or waters owned or controlled by the United States to a site for operations” will be granted, and no operations shall be conducted, until NPS has approved a plan of operations. A plan of operations must contain “[p]rovisions for reclamation” and a “breakdown of the estimated costs to be incurred during the implementation of the reclamation plan.” (36 CRF 9.36(a)(12) and (13)) The activities that an operator must conduct at the end of operations are detailed in 36 CFR 9.36, Reclamation requirements.

3.3.1 Bond Types and Bonding Amounts

Prior to the approval of a plan of operations, an operator must file a “suitable performance bond with satisfactory surety”. (36 CFR 9.48(a)) Alternatively, an operator may deposit with the NPS cash or negotiable bonds of the United States Government. (36 CFR 9.48(b))

The amount of the bond or security deposit (cash or United States Government bonds) is to include the following:

- The estimated cost of reclaiming the site. (36 CFR 9.48(d)(1))
- An amount set by the Superintendent of the park to bond against the liability of the operator for any damages to federally-owned or controlled lands, waters, or resources resulting from the operator’s failure to comply with the plan of operations or applicable permit. This amount is capped at $50,000 for each well site or operation (36 CFR 9.48(d)(2). The total bond or security deposit is capped at $200,000 per unit; an operator may substitute a blanket bond of $200,000 for individual bonds.

3.3.1.1 Setting and Adjusting Bonding Amounts

There is nothing in regulation that provides guidance on how the estimated costs of reclamation are to be determined.

There is no regulated period for the review or adjusting of bonding amounts. Per 36 CFR 9.34, Transfers of interest, when a rights owner sells, assigns, or otherwise conveys all or any of their rights, the Superintendent can prohibit the new rights owner from operating until the new owner files "a suitable substitute performance bond" for the bond provided by the original rights owner. This provides the Superintendent an opportunity to increase the bonding amount if necessary.

3.4 Bonding, Oil and Gas Operation, United States Fish and Wildlife Service

USFWS regulations that govern its oversight of oil and gas operations on national wildlife refuges lands are found generally at CFR Title 50—Wildlife and Fisheries, Part 29—Land Use Management. The sum of USFWS regulation of oil and gas operations is captured in 50 CFR 29.32, Mineral rights reserved and excepted, which reads in whole:

> "Persons holding mineral rights in wildlife refuge lands by reservation in the conveyance to the United States and persons holding mineral rights in such lands which rights vested prior to the acquisition of the lands by the United States shall, to the greatest extent practicable, conduct all exploration, development, and production operations in such a manner as to prevent damage, erosion, pollution, or contamination to the lands, waters, facilities and vegetation of the area. So far as is practicable, such operations must also be conducted without interference with the operation of the refuge or disturbance to the wildlife thereon. Physical occupancy of the area must be kept to the minimum space compatible with the conduct of efficient mineral operations. Persons conducting mineral operations on refuge areas must comply with all applicable Federal and State laws and regulations for the protection of wildlife and the administration of the area. Oil field brine, slag, and all other waste and contaminating substances must be kept in the smallest practicable area, must be confined so as to prevent escape as a result of rains and high water or otherwise, and must be removed from the area as quickly as practicable in such a manner as to prevent contamination, pollution, damage, or injury to the lands, waters, facilities, or vegetation of the refuge or to wildlife. Structures and equipment must be removed from the area when the need for them has ended. Upon the cessation of operations the area shall be restored as nearly as possible to its condition prior to the commencement of operations. Nothing in this section shall be applied so as to contravene or nullify rights vested in holders of mineral interests on refuge lands."

If the subsurface minerals beneath USFWS managed lands are owned/managed by the BLM, or if certain language is contained in the property deed or other documentation, an operator must obtain a mandatory Special Use Permit (SUP) for the operation of oil and gas infrastructure. However, the USFWS only has the ability to require a performance bond in conjunction with a mandatory SUP. When there is no mandatory SUP, the Service has no statutory or regulatory authority to impose a bond requirement. If an operator voluntarily agrees to a performance bond in the negotiation of a voluntary SUP, then the Refuge Manager is within his/her rights to determine with the operator the mutually agreed upon terms of the performance bond (USFWS 2012).

USFWS Policy 612 FW 2, Oil and Gas, Part 2.9, Procedural Requirements for Permitting Oil and Gas Activities, Subpart C, Performance Bond, of the Policy notes:

> "A performance bond or certificate of insurance will be required for exploration, development, and production activities. If an operator possesses an existing State or national bond of sufficient coverage, a new bond may not be required. The project leader will determine the potential costs involved should it become necessary for the Service to pay for restoration of damaged areas. These costs will be fully covered by the performance bond or certificate of insurance. Documentation of the existence of the required bond or certificate and its coverage of the Service must be submitted to the project leader prior to issuance of a Special Use Permit."

The Policy also "[e]stablishes the Management of Oil and Gas Activities on National Wildlife Refuge Lands Handbook as the technical reference manual Refuge Managers must use when working on oil and gas projects." The Handbook notes that "[t]he Service recommends a performance bond or certificate of insurance for exploration, development, and production activities."

3.4.1 Bonding Amount

The Handbook states:

> "The proper bond amount should fully cover the potential costs involved, should it become necessary for the Service to pay for restoration of damaged areas. A certificate of insurance fully covering the costs may also be sufficient. The determination of the proper bond amount is based on a written evaluation prepared for a proposed plan of operations of the estimated reclamation cost plus the liability amount."

Note that the bond amount does not represent the limit of liability for damage to refuge resources. The Handbook notes that "[u]nder the Service's cost recovery policy, the operator is responsible for restoration of damaged areas, or for "'other than reasonable surface damages.'"

3.4.2 Acceptable Bonding Mechanisms

The Handbook identifies only a corporate surety bond as an appropriate performance bond. However, the Handbook does provide for an operator to submit a certificate of liability insurance in place of a performance bond. The Handbook recommends a minimum insurance coverage of $300,000 for each occurrence and $500,000 aggregate.

3.5 Bonding, Mining Operations, Bureau of Land Management

BLM regulations related to the extraction of locatable minerals are found generally at CFR Title 43—Public Lands: Interior, Subtitle B, Chapter II—Bureau of Land Management, Department of the Interior. Specifically, regulations related to the bonding of mining operations are found at 43 CFR 3809.500 et seq.

The types and amounts of financial guarantees required for mining activities are determined by the number of activities (as indicated by the filing of a notice or plan of operations with BLM) that a single entity undertakes. If an entity has filed only one notice or plan of operations, it can provide an individual financial guarantee in an amount sufficient to cover the cost of reclaiming areas disturbed under the single notice or plan of operations. If an entity has filed multiple notices or plans of operation, it can provide an individual financial guarantee for each operation or a blanket financial guarantee that covers either statewide or national operations. Alternately, an entity may demonstrate to BLM that it has in place a financial guarantee under state law or regulation (43 CFR 3809.551).

3.5.1 Individual Financial Guarantees

3.5.1.1 Amount and Covered Activities

Individual financial guarantees must be provided in an amount sufficient to "cover the estimated cost as if BLM were to contract with a third party to reclaim…operations according to the reclamation plan." (43 CFR 3809.552(a)) In addition, BLM may require an entity to "establish a trust fund or other funding mechanism…to ensure the continuation of long-term treatment to achieve water quality standards and for other long term, post-mining maintenance requirements." (43 CFR 3809.552(c)) BLM may identify the need for, and may require, a long-term maintenance trust fund or other funding mechanism during plan review or later.

The amount of a financial guarantee is initially determined by the entity filing the notice or plan of operations. BLM reviews and may accept or decline the amount as appropriate. Financial guarantees are reviewed by BLM field offices. Some state offices (for instance, the BLM's Nevada State Office) and field offices have developed standardized reclamation cost calculators to assist in the review of proposed financial guarantee amounts. There is no nationwide cost calculator, but many of the state or field office-level guidance documents reviewed recommend that the Office of Surface Mining Reclamation and Enforcement Handbook for Calculation of Reclamation Bond Amounts and the BLM Solid Minerals Reclamation Handbook H-3042-1 can be used to estimate costs, in addition to a variety of private sector construction cost estimating tools.

3.5.1.2 Phased or Multi-Part Activities

Operators may post an individual financial guarantee for a portion of an operation. The financial guarantee must be in an amount sufficient to cover all reclamation costs from that portion of the operation (43 CFR 3809.553).

3.5.1.3 Review of Individual Financial Guarantees

BLM periodically reviews the estimated cost of reclamation and the adequacy of financial guarantee amounts. Reclamation cost estimates for Notice operations must be reviewed every 2 years or at the time of the Notice extension, and reclamation cost estimates for Plans of Operations must be reviewed at least every 3 years. Further, the BLM has the authority to require a more frequent review of the reclamation cost estimate at the discretion of the Field Manager (BLM n.d.). The amount and terms of a partial financial guarantee are reviewed by BLM at least annually (43 CFR 3809.553).

3.5.1.4 Acceptable Forms for Individual Financial Guarantees

Per 43 CFR 3809.555, the following instruments may be acceptable for an individual financial guarantee. The State Director has the discretion to approve what instruments will be accepted in their state.

- Surety bonds issued by qualified surety companies approved by the U.S. Department of the Treasury
- Cash, deposited and maintained in a federal depository account
- Irrevocable letters of credit from a bank or financial institution organized or authorized to transact business in the United States
- Certificates of deposit or savings accounts not in excess of the maximum insurable amount as set by the U.S. Federal Deposit Insurance Corporation
- Negotiable United States Government, State, and Municipal securities or bonds
- Investment-grade rated securities having a Standard and Poor's rating of AAA or AA or an equivalent rating from a nationally recognized securities rating service
- Insurance, if its form and function is such that the funding or enforceable pledges of funding are used to guarantee performance of regulatory obligations in the event of default on such obligations

by the operator. Insurance must have an A.M. Best rating of "superior" or an equivalent rating from a nationally recognized insurance rating service.[3]

3.5.2 Blanket Financial Guarantee

An entity may arrange for a blanket financial guarantee to cover activities on a statewide basis or to cover activities across the nation. The types of acceptable financial guarantees, review periods, and processes for determining the amount of a blanket bond are identical to those for an individual financial guarantee.

3.6 Bonding, Mining Operations, U.S. Forest Service

USFS regulations related to leasing for mining activities are found generally at CFR Title 36—Parks, Forests, and Public Property, Part 228—Minerals, Subpart A, Locatable Minerals.

The basis for USFS bonding of mining activities is found in 36 CFR 228.8, Requirements for environmental protection, (g) Reclamation, which states in whole:

> "Upon exhaustion of the mineral deposit or at the earliest practicable time during operations, or within 1 year of the conclusion of operations, unless a longer time is allowed by the authorized officer, operator shall, where practicable, reclaim the surface disturbed in operations by taking such measures as will prevent or control onsite and off-site damage to the environment and forest surface resources including:
>
> (1) Control of erosion and landslides;
> (2) Control of water runoff;
> (3) Isolation, removal or control of toxic materials;
> (4) Reshaping and revegetation of disturbed areas, where reasonably practicable; and
> (5) Rehabilitation of fisheries and wildlife habitat."

In addition, 36 CFR 228.10, Cessation of operations, removal of structures and equipment, states in part that "[u]nless otherwise agreed to by the authorized officer, operator shall remove within a reasonable time following cessation of operations all structures, equipment and other facilities and clean up the site of operations."

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[3] Before operations begin and by the end of each calendar year thereafter, a certified statement describing the nature and market value of the instruments maintained in the account, and including any current statements or reports furnished by the brokerage firm to the operator or mining claimant concerning the asset value of the account must be provided to BLM. The market value of the account instruments must be reviewed by December 31 of each year to ensure that their market value continues to be not less than the required dollar amount of the financial guarantee. When the market value of the account instruments has declined by more than 10 percent of the required dollar amount of the financial guarantee, additional instruments must be added to the trust account so that the total market value of all account instruments is not less than the required dollar amount of the financial guarantee. If the total market value of trust account instruments exceeds 110 percent of the required dollar amount of the financial guarantee, BLM may authorize a release of that portion of the account that exceeds 110 percent of the required financial guarantee (43 CFR 3809.556).

36 CFR 228.13, Bonds, states in whole:

> "(a) Any operator required to file a plan of operations shall, when required by the authorized officer, furnish a bond conditioned upon compliance with §228.8(g), prior to approval of such plan of operations. In lieu of a bond, the operator may deposit into a Federal depository, as directed by the Forest Service, and maintain therein, cash in an amount equal to the required dollar amount of the bond or negotiable securities of the United States having market value at the time of deposit of not less than the required dollar amount of the bond. A blanket bond covering nationwide or statewide operations may be furnished if the terms and conditions thereof are sufficient to comply with the regulations in this part.
> (b) In determining the amount of the bond, consideration will be given to the estimated cost of stabilizing, rehabilitating, and reclaiming the area of operations.
> (c) In the event that an approved plan of operations is modified in accordance with §228.4 (d) and (e), the authorized officer will review the initial bond for adequacy and, if necessary, will adjust the bond to conform to the operations plan as modified.
> (d) When reclamation has been completed in accordance with §228.8(g), the authorized officer will notify the operator that performance under the bond has been completed: Provided, however, That when the Forest Service has accepted as completed any portion of the reclamation, the authorized officer shall notify the operator of such acceptance and reduce proportionally the amount of bond thereafter to be required with respect to the remaining reclamation."

3.6.1 United States Forest Service, Mining, Acceptable Financial Securities

As stated in 36 CFR 228.13(a), acceptable financial securities for mining operations on USFS surface estate include a bond, a cash deposit, or negotiable securities of the United States.

An operator may post a blanket bond to cover statewide or nationwide operations. The financial securities listed in 36 CFR 228.13(a) may be used for a blanket bond.

3.7 Bonding, Mining Operations, National Park Service

NPS regulations related to its control of mining activities on park lands are found generally at CFR Title 36—Parks, Forests, and Public Property. Specifically, regulations related to the bonding of mining operations are found at 36 CFR 9, Minerals Management, Subpart A—Mining and Mining Claims.

Per 36 CFR 9.9(a), "no operations shall be conducted…until a plan of operations has been submitted…and approved." A plan of operations must contain "[a] mining reclamation plan." (36 CFR 9.9(b)(6)) The activities that an operator must conduct contemporaneous with operations, or at the end of operations, are contained in 36 CFR 9.11, Reclamation requirements.

3.7.1 Bond Types and Bonding Amounts

Upon approval of a plan of operations, an operator must file a "suitable performance bond with satisfactory surety". (36 CFR 9.13(a)) Alternatively, an operator may deposit with the NPS cash or negotiable bonds of the United States Government (36 CFR 9.13(b)).

The amount of the bond or security deposit (cash or United States Government bonds) is to be "equal to the estimated cost of completion of reclamation requirements either in their entirety or in a phased schedule for their completion as set forth in the approved, supplemented or revised plan of operations." (36 CFR 9.13(d))

3.7.1.1 Setting and Adjusting Bonding Amounts

There is nothing in regulation that provides guidance on how the estimated costs of reclamation are to be determined.

There is no regulated period for the review or adjusting of bonding amounts. Per 36 CFR 9.13(d), "In the event that an approved plan of operations is revised or supplemented…the Superintendent may adjust the amount of the bond or security deposit to conform to the plan of operations as modified." This provides the Superintendent an opportunity to increase the bonding amount if necessary.

3.8 Bonding, Mining Operations, U.S. Fish and Wildlife Service

The regulations at 50 CFR 29.31 and 29.32, as cited above, are the sole USFWS regulations related to mining operations on USFWS-managed lands. USFWS Policy 612 FW 1, Minerals and Mining, Part 1.9, Permits for Mining Activity, Subpart C, Mining Operations, notes that the "mineral owner is responsible for complying with all applicable local, State, and Federal laws governing mineral development, including procurement of necessary bonds…" There is nothing in regulation or guidance that specifies what bonds are necessary.

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FEDERAL JURISDICTION AREAS—OFFSHORE

1. Background and History

In 1953, the Submerged Lands Act (SLA) granted individual states rights to the natural resources of submerged lands from the coastline to no more than 3 nautical miles (5.6 kilometers [km]) into the Atlantic, Pacific, and Arctic oceans and the Gulf of Mexico. Along the Texas coast and the west coast of Florida, state jurisdiction extends from the coastline to no more than 3 marine leagues (16.2 km) into the Gulf of Mexico.

The SLA reaffirmed the federal claim to the lands of the Outer Continental Shelf (OCS), which consists of those submerged lands seaward of state jurisdiction. The SLA led to the Outer Continental Shelf Lands Act (OCSLA) later in 1953. The OCSLA and subsequent amendments outline the federal responsibility over the submerged lands of the OCS, and authorize the Secretary of the Interior to lease those lands for mineral development.

There are four OCS areas: the OCS off the coast of the states of Washington, Oregon, California, and Hawaii; the OCS off the coast of the State of Alaska; the Atlantic Ocean OCS; and the Gulf of Mexico OCS. The most active of the three OCS areas is the Gulf of Mexico OCS, which is a mature oil and gas province with operators ranging from independents to international major operating platforms, pipelines, and other assets ranging in age from the recently installed to those installed as early as the 1950s. In general terms, the deep-water regions of the Gulf of Mexico OCS tend to be the province of international major oil firms, with smaller firms operating in shallower waters.

2. Regulatory Structure

The leasing of federal OCS lands and oversight of operations thereon has been the province of the Department of the Interior since the passage of OCSLA. Today, after several restructurings, two agencies are involved with the leasing of OCS lands and oversight of operations:

- The Bureau of Ocean Energy Management (BOEM) is responsible for managing development of the nation’s offshore resources in an environmentally and economically responsible way. Functions include: Leasing, Plan Administration, Environmental Studies, National Environmental Policy Act (NEPA) Analysis, Resource Evaluation, Economic Analysis, and the Renewable Energy Program.
- The Bureau of Safety and Environmental Enforcement (BSEE) is responsible for enforcing safety and environmental regulations. Functions include all field operations: Permitting and Research, Inspections, Offshore Regulatory Programs, Oil Spill Response, and newly formed Training and Environmental Compliance functions.

BOEM divides the OCS into three areas: the Gulf of Mexico area; the California, Oregon, Washington, and Hawaii offshore areas; and the Alaska offshore area. The Atlantic Ocean OCS is included in the Gulf of

Mexico area. Area-wide bonds issued in the Gulf of Mexico will cover oil and gas operations off shore in the Atlantic Ocean.

3. Bonding/Financial Securities: Oil, Gas, and Sulfur

The BOEM has the primary authority to manage the financial risks to the government associated with the development of energy and mineral resources on the OCS. BOEM has program oversight for OCS financial assurance requirements set forth in 30 CFR parts 550, 556 subpart I, 581 subpart C, 582 subpart D, 585 subpart E, and in § 551.7, all of which are promulgated pursuant to OCSLA (43 U.S.C. 1331 et seq.).

3.1 Activities/Infrastructure that must be Bonded: Oil, Gas, and Sulfur

BOEM currently requires lessees to provide performance bonds and/or one of various alternative forms of financial assurance to ensure compliance with the terms and conditions of leases, rights-of-use and easements (RUEs), and pipeline rights-of-way (ROWs).

3.2 Bonding Amounts: Oil, Gas, and Sulfur

Bonding ensures that all entities performing offshore oil and gas activities can provide adequate financial resources to protect the U.S. government from incurring financial loss. Each offshore lease is reviewed to ensure the working interest owners have adequate financial coverage to provide for the performance of all lease obligations, including rent, royalties, environmental damage, cleanup and restoration activities, abandonment and site clearance, and other lease obligations. Bonding amounts are determined by the activity on a lease as discussed below.

3.2.1 Lease Issuance

Prior to issuing a new lease, or approving the transfer of a lease, BOEM requires that a lessee provide a lease-specific or area-wide bond in the amount of $50,000 or $300,000 (if an operator has not submitted an exploration plan) or a lease-specific or area-wide bond in the amount of $200,000 or $1,000,000 (if an operator has submitted an exploration plan) (30 Code of Federal Regulations [CFR] §§ 556.52 and .53)

3.2.2 Exploration

Prior to beginning exploration on a lease, the lessee must post a lease-specific or area-wide bond in the amount of $200,000 or $1,000,000, respectively (30 CFR § 556.53(a)). The amount of an existing lease issuance bond as described above can be increased to satisfy the exploration lease bond.

3.2.3 Development and Production

Prior to undertaking development and production activities, the lessee must post a lease-specific or area-wide bond in the amount of $500,000 or $3,000,000, respectively (30 CFR § 556.53(b)).

3.2.3.1 Modification of Bonding Amount

BOEM may decrease development and production bonding amounts. Per 30 CFR § 556.53(c), if a lessee demonstrates to the satisfaction of BOEM that wells and platforms can be abandoned and removed and the drilling and platform sites can be cleared of obstructions for less than the amount of lease bond coverage required for development and production activities, BOEM may accept a lease surety bond in an amount less than the prescribed amount but not less than the amount of the cost for well abandonment, platform removal, and site clearance.

3.2.4 Right-of-Use and Easement

Before a RUE on the OCS is issued, BOEM must be furnished with a surety bond in the amount of $500,000 (30 CFR § 550.166).

3.2.5 Pipeline Right-of-Way

A pipeline ROW holder must provide and maintain a $300,000 bond that guarantees compliance with the terms and conditions of the ROW held in an OCS area. The pipeline ROW bond is, in essence, a blanket bond covering an entire OCS area rather than a single pipeline (30 CFR §550.1011). Pipeline ROW bonds must be provided in addition to the other bonds discussed above.

Table 3.2-1 Financial Security Amounts

Lease Activity	Lease-Specific Bond Amount	Area-Wide Bond Amount
No Approved Operational Activity	$50,000	$300,000
Exploration Plan	$200,000	$1,000,000
Development Production Plan	$500,000	$3,000,000
Right-of-Use and Easement	N/A	$500,000
Pipeline Right-of-Way	N/A	$300,000

Source: 30 CFR § 550

3.2.6 Supplemental Financial Security

BOEM may determine that additional financial security (amounts greater than those described above for lease issuance, exploration, development and production, RUE, or pipeline ROW) are necessary to ensure that a lessee meets its obligations (30 CFR § 556.53(d)).

The determination that additional financial security is necessary is based on BOEM’s evaluation of a lessee’s ability to carry out present and future financial obligation as evidenced by the lessee having or showing:

- Financial capacity substantially in excess of existing and anticipated lease and other obligations, as evidenced by audited financial statements (including auditor's certificate, balance sheet, and profit and loss sheet)
- Projected financial strength significantly in excess of existing and future lease obligations based on the estimated value of your existing OCS lease production and proven reserves of future production
- Business stability based on 5 years of continuous operation and production of oil and gas or sulfur in the OCS or in the onshore oil and gas industry
- Reliability in meeting obligations based on credit rating(s) or trade references, including names and addresses of other lessees, drilling contractors, and suppliers with whom you have dealt
- Record of compliance with laws, regulations, and lease terms.

BOEM will determine the amount of supplemental bond required, taking into consideration a lessee’s cumulative obligations to abandon wells, remove platforms and facilities, and clear the seafloor of obstructions. If additional financial security is warranted, a lessee may provide a supplemental bond or bonds, or may increase the amount on an existing bond.

BOEM may determine that a supplemental bond is not necessary for a lease if at least one record title owner meets the financial strength and reliability criteria detailed in the Notice to Lessees and Operators No. 2008-N07, "Supplemental Bond Procedures." Currently, approximately 90 percent of leases do not require an additional bond or supplemental financial assurance because at least one record title owner has been determined to meet these criteria. Additional bonding and supplemental financial assurance practices utilize decommissioning cost estimates and analyses provided by BSEE.

3.3 Acceptable Financial Securities: Oil, Gas, and Sulfur

BOEM currently relies primarily upon surety bonds to provide basic protection against risks associated with a lessee's or operator's failure to meet regulatory and lease requirements. However, other financial securities may be found acceptable as described below.

All financial securities must be payable upon demand to the BOEM Regional Director, must guarantee compliance with all of the lessee’s obligations under the lease and regulations in this chapter, and must guarantee compliance with the obligations of all lessees, operating rights owners, and operators on the lease. The amount of a surety may vary depending on the form of the surety and how long the surety is effective.

Co-principals are not acceptable on any required bond.

3.3.1 Surety Bond

A BOEM-specified surety instrument must be in a form specified in BOEM's instructions. BOEM provides written information and standard forms for BOEM-specified surety instrument requirements. Surety bonds must be issued by a surety that the U.S. Department of the Treasury (Treasury) certifies as an acceptable surety on federal bonds and that is listed in the current Treasury Circular No. 570. BOEM uses a bank-rating service to determine whether a financial institution has an acceptable rating to provide a surety instrument adequate to indemnify the lessor from loss or damage. Bonds must be noncancellable, and must continue in full force and effect even though an event occurs that could diminish, terminate, or cancel a surety obligation under state surety law.

3.3.2 Treasury Securities

A lessee may pledge Treasury securities instead of a bond. The Treasury securities pledged must be negotiable for an amount of cash equal to the value of the bond they replace. Lessees must monitor the value of the Treasury securities; if their market value falls below the level of the required bond coverage, additional Treasury securities to raise the value of the securities must be pledged.

3.3.3 Other Form of Security

Per 30 CFR §556.54(e)(3), another form of security may be approved by the Regional Director if they determine that the alternative security protects the interests of the United States to the same extent as the required bond. As for Treasury securities, the value of the other form of security must be monitored. If its market value falls below the level of bond coverage required under this subpart, the lessee must pledge additional securities to raise the value of the securities pledged to the required amount.

3.3.4 Third-Party Guarantee

Per 30 CFR 556.57, BOEM may accept a third-party guarantee instead of a supplemental or additional financial security as may be required under 30 CFR § 556.53(d). BOEM places a range of conditions on both the guarantor and the guarantee, including the financial strength of the guarantor.

3.3.5 Lease-Specific Abandonment Accounts

BOEM may authorize a lease-specific abandonment account in a federally insured institution in lieu of additional bond security that ensures compliance with current obligations. The account must provide that funds may not be withdrawn without the written approval of the relevant BOEM Regional Director. Any interest paid on funds in a lease-specific abandonment account will be treated as other funds in the account unless the Regional Director authorizes in writing the payment of interest to the party that deposits the funds. The Regional Director may allow the pledge of Treasury securities that are made payable upon demand to the Regional Director to satisfy an obligation to make payments into a lease-specific abandonment account. Before the amount of funds in a lease-specific abandonment account equals the maximum insurable amount as determined by the Federal Deposit Insurance Corporation or the Federal Savings and Loan Insurance Corporation, the institution managing the account must use the funds in the account to purchase Treasury securities pledged to BOEM. The required obligation may be associated with oil and gas production from a lease other than the lease bonded through the lease-specific abandonment account.

3.3.6 Supplemental Bonding Guidance

BOEM publishes Notices to Lessees and Operators (NTLs) to provide guidance and clarifications on how it will implement its regulations.

NTL No. 2008-N07, Supplemental Bond Procedures (which is applicable nationwide), clarifies the procedures and criteria used to determine when a supplemental bond is required to cover potential decommissioning liability. NTL No. 2008-N07 contains discussions on the timing of review of potential lease, RUE, and ROW decommissioning liability, the determination of financial strength and reliability and decommissioning liability, identification of acceptable forms of supplemental bonding, the use of a third-party indemnity in lieu of a supplemental bond, and termination of supplemental bonds or third-party indemnities or a determination that a supplemental bond is not necessary.

3.4 Proposed Rule Update

On August 19, 2014, BOEM issued an Advance Notice of Proposed Rulemaking (ANPR) on Risk Management, Financial Assurance, and Loss Prevention. As stated in the summary to the ANPR:

> "BOEM is seeking comments and information regarding its effort to update its regulations and program oversight for Outer Continental Shelf (OCS) financial assurance requirements. When BOEM's existing bonding regulations were originally drafted and first implemented, the principal risks associated with OCS leases were nonpayment of rents and royalties, noncompliance with laws and regulations, and potential problems due to bankruptcy. While potentially significant, such risks were generally well-known and of limited complexity, size and scope.
>
> Due to increasingly complex business, functional, organizational and financial issues and vast differences in costs associated with expanded and varied offshore activities, BOEM has recognized the need to develop a comprehensive program to assist in identifying, prioritizing, and managing the risks associated with industry activities on the OCS. BOEM intends to design and implement a more robust and comprehensive risk management, financial assurance and loss prevention program to address these complex issues and cost differences associated with offshore operations." (BOEM 2014)

The ANPR identifies four major topics on which BOEM is seeking input:

- Identification of Pertinent Risks/Liabilities
- Risk Monitoring and Risk Management
- Demonstrating Financial Assurance Over Project Lifecycles
- Financial Assurance, Bonding Levels, and Requirements

At the time this report was drafted, the public comment period had not yet closed (due to the complexity of issues under consideration, BOEM extended the public comment period to November 19. 2014). At the direction of DNR, updates to this section will be made when comments submitted in response to the ANPR are made available for public review.

4. Bonding/Financial Securities: Minerals other than Oil, Gas, or Sulfur

The regulations at 30 CFR 580 et seq. address the leasing of OCS lands and the exploration for and production of minerals other than oil, gas, or sulfur.

4.1 Activities/Infrastructure that must be Bonded: Minerals other than Oil, Gas, or Sulfur

Per 30 CFR § 581.33(c), prior to the commencement of any activity on a lease(s), the lessee shall submit a surety or personal bond. Prior to the approval of a Delineation, Testing, or Mining Plan, the bond amount shall be adjusted, if appropriate, to cover the operations and activities described in the proposed plan.

As for oil, gas, and sulfur, the OCS is divided into three areas: the Gulf of Mexico area, including the Atlantic Coast states offshore area; the Pacific Coast states of California, Oregon, Washington, and Hawaii offshore area; and the State of Alaska offshore area.

A separate bond shall be required for each area. An operator's bond may be submitted for a specific lease(s) in the same amount as the lessee's bond(s) applicable to the lease(s) involved.

4.2 Bonding Amounts: Minerals other than Oil, Gas, or Sulfur

A bond in the minimum amount of $50,000 to cover the lessee's obligations under the lease shall be submitted prior to the commencement of any activity on a leasehold. A $50,000 bond shall not be required on a lease if the lessee already maintains or furnishes a $300,000 bond conditioned on compliance with the terms of leases for OCS minerals other than oil, gas, and sulfur held by the lessee on the OCS for the area in which the lease is located. Prior to approval of a Delineation, Testing, or Mining Plan, the bond amount shall be adjusted, if appropriate, to cover the operations and activities described in the proposed plan.

4.3 Acceptable Financial Securities: Minerals other than Oil, Gas, or Sulfur

All bonds furnished by a lessee or operator must be in a form approved by the Associate Director for Offshore Energy and Minerals Management. Only those surety bonds issued by qualified surety companies approved by the Treasury shall be accepted (see Treasury Circular No. 570 and any supplemental or replacement circulars).

Personal bonds shall be accompanied by a cashier's check, certified check, or negotiable Treasury bonds of a value equal to the amount specified in the bond. Negotiable Treasury bonds shall be accompanied by a proper conveyance of full authority to the Director to sell such securities in case of default in the performance of the terms and conditions of the lease.

5. Bonding/Financial Securities: Commercial Leases

The regulations at 30 CFR 585 et seq. establish procedures for issuance and administration of leases, ROW grants, and RUE grants for renewable energy production on the OCS and RUEs for the alternate use of OCS facilities for energy or marine-related purposes.

5.1 Activities/Infrastructure that must be Bonded: Commercial Leases

Per 30 CFR § 581.33(c), prior to the commencement of any activity on a lease(s), the lessee shall submit a surety or personal bond. Prior to the approval of a Delineation, Testing, or Mining Plan, the bond amount shall be adjusted, if appropriate, to cover the operations and activities described in the proposed plan.

As for oil, gas, and sulfur, the OCS is divided into three areas: the Gulf of Mexico area, including the Atlantic Coast states offshore area; the Pacific Coast states of California, Oregon, Washington, and Hawaii offshore area; and the State of Alaska offshore area.

A separate bond shall be required for each area. An operator's bond may be submitted for a specific lease(s) in the same amount as the lessee's bond(s) applicable to the lease(s) involved.

5.2 Bonding Amounts: Commercial Leases

Bonding amounts differ according to the activity on the lease, as shown in the sections below (30 CFR § 585.516). The minimum amounts may be adjusted every 5 years to reflect changes in the Consumer Price Index-All Urban Consumers (CPI-U) or a substantially equivalent index if the CPI-U is discontinued.

5.2.1 Commercial Lease Issuance/Assignment of an Existing Commercial Lease

Before BOEM will issue a commercial lease or approve an assignment of an existing commercial lease, the lessee, assignee, or designated lease operator must guarantee compliance with all terms and conditions of the lease by providing either a lease-specific bond or another approved financial assurance instrument guaranteeing performance up to $100,000 (minimum).

5.2.2 Site Assessment Plan Approval

Prior to approving a Site Assessment Plan (SAP), BOEM will review the SAP and may determine that a supplemental bond is required in addition to the minimum lease-specific bond. The supplemental bond may be necessary due to the complexity, number, and location of any facilities involved at the site.

5.2.3 Construction and Operations Plan Approval

Prior to approving a Construction and Operations Plan (COP), BOEM may require a supplemental bond or other financial assurance, in an amount determined by BOEM based on the complexity, number, and location of all facilities involved in the planned activities and commercial operation. The supplemental financial assurance requirement is in addition to the lease-specific bond and, if applicable, any previous supplemental bond associated with SAP approval.

5.2.4 Installation of Facilities

Prior to installing approved facilities, a decommissioning bond or other financial assurance, in an amount determined by BOEM based on anticipated decommissioning costs, must be filed. The financial assurance for decommissioning can be filed in accordance with the number of facilities installed or being installed (i.e., staggered over time). BOEM must approve the schedule for providing the appropriate financial assurance coverage.

5.2.4.1 Establishing Financial Assurance Requirements

BOEM bases the determination for the amounts of the SAP, COP, and decommissioning financial assurance requirements on estimates of the cost to meet all accrued lease obligations (30 CFR § 585.517). The amounts are determined on a case-by-case basis. In all cases, the amount of the financial assurance must be no less than the amount required to meet all lease obligations, including:

- The projected amount of rent and other payments due the government over the next 12 months
- Any past due rent and other payments
- Other monetary obligations
- The estimated cost of facility decommissioning.

BOEM may, at its discretion, adjust the amount of a supplemental or decommissioning financial assurance based on increases or decreases in the lessee's/operator's cumulative potential obligations and liabilities.

BOEM may also approve a lessee/operator-requested reduction in the amount of a supplemental or decommissioning financial assurance.

5.2.5 Financial Assurance for Limited Leases, Right-of-Way Grants, and Right-of-Use Grants

Before BOEM issues a limited lease, ROW grant, or RUE grant, the lessee or designated operator must guarantee compliance with all terms and conditions of the lease or grant by providing either a $300,000 minimum, lease- or grant-specific bond, or another approved financial assurance instrument meeting that minimum amount. The minimum amount may be adjusted every 5 years to reflect changes in the CPI-U or a substantially equivalent index if the CPI-U is discontinued.

5.3 Acceptable Financial Assurance Instruments: Commercial Leases

Acceptable financial assurance instruments are contained in 30 CFR §§ 585.525, 526, 527, 528, and 529. Regardless of type of financial assurance instrument, the instrument must be payable to BOEM upon demand, and guarantee compliance of all lessees, grant holders, operators, and payors with all terms and conditions of the lease or grant, any subsequent approvals and authorizations, and all applicable regulations. All bonds and other forms of financial assurance must be on or in a form approved by BOEM.

5.3.1 Surety Bonds

Surety bonds must be issued by an approved surety listed in the current Treasury Circular 570. The surety bond cannot exceed the underwriting limit listed in the current Treasury Circular 570, except as permitted therein. The lessee or designate operator and a qualified surety must execute the bond.

5.3.2 Alternate Financial Assurance Instruments

A range of alternate financial assurance instruments may be utilized, including

- Treasury securities
- Cash in an amount equal to the required dollar amount of the financial assurance, to be deposited and maintained in a federal depository account of the Treasury by BOEM
- Certificates of deposit or savings accounts in a bank or financial institution
- Negotiable U.S. government, state, and municipal securities or bonds having a market value of not less than the required dollar amount of the financial assurance and maintained in a Securities Investors Protection Corporation insured trust account by a licensed securities brokerage firm for the benefit of the BOEM
- Investment-grade rated securities having a Standard and Poor's rating of AAA or an equivalent rating from a nationally recognized securities rating service having a market value of not less than

the required dollar amount of the financial assurance and maintained in a Securities Investors Protection Corporation insured trust account by a licensed securities brokerage firm for the benefit of BOEM

- Insurance, if its form and function is such that the funding or enforceable pledges of funding are used to guarantee performance of regulatory obligations in the event of default on such obligations by the lessee. Insurance must have an A.M. Best rating of “superior” or an equivalent rating from a nationally recognized insurance rating service
- A third-party guaranty.

Note that if a Treasury security is used, the lessee/designated operator must post 115 percent of the financial assurance amount. The value of other alternate financial assurance instruments must be monitored and maintained at a level that provides 115 percent of the required amount.

In addition to the above, a lessee or designated operator may establish a lease- or grant-specific decommissioning account to meet the financial assurance requirements related to decommissioning. The account must be established in a federally insured institution, the funds must be payable to BOEM and pledged to meet the lease or grant decommissioning and site clearance obligations, and the account must be fully funded within a BOEM-prescribed time frame. BOEM will estimate the cost of decommissioning to include site clearance. BOEM may require the lessee/designated operator to commit a specified stream of revenues as payment into the account so that the account will be fully funded. The commitment may include revenue from other operations (30 CFR § 585.529).

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STATE REPORT—CALIFORNIA

1. Background and History

The State of California ranked third in the nation in crude oil production in 2013, despite an overall decline in production rates since the mid-1980s. Crude oil production is approximately 577,000 barrels per day; approximately 39,000 barrels per day is produced from offshore state lands in southern California (DOGGR 2014). The offshore fields are produced from onshore sites, offshore platforms, and offshore man-made islands.

Offshore state oil and natural gas resources were originally discovered and developed primarily by large firms (e.g., Exxon, Chevron, Shell, ARCO, Mobil, and Occidental [Oxy] among others). Starting in the early 1990s, many of these firms began to exit the market through sales of infrastructure and assignment of leases to smaller independent firms including Venoco, DCOR, Breitburn Energy Corporation, and Greka Energy. In some cases, leases have changed hands twice: Exxon and Chevron assigned leases to Plains Exploration and Production Company, who in turn assigned them to DCOR. At this time, the only major firm producing oil from a state lease is Oxy.

The transition of operations based in California from large major firms to smaller independent firms is similar to the transition currently being realized in Alaskan fields. This transition was realized on state leases, with significant infrastructure installed thereon (e.g., offshore platforms, man-made islands), making California a useful equivalent to Alaska.

2. Regulatory Structure

The State Lands Commission (SLC) has jurisdiction and management control over public lands of the state. Generally, these state lands include all ungranted sovereign lands (lands lying below tidal and navigable waters), school lands (lands granted by Congress for the purpose of funding a public school system), swamp and overflowed lands, and some proprietary lands. The state holds the mineral rights to these lands. The SLC's Mineral Resources Management Division is responsible for the management and administration of oil and gas resources contained on these state lands. Oil and gas leases are currently held by production in paying quantities.

The Division of Oil, Gas, and Geothermal Resources (DOGGR) within the Department of Conservation is responsible for overseeing oil and gas activities on state and private lands, and ensuring compliance with state oil and gas lease terms.[4] DOGGR supervises the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells on state and private lands, among

[4] DOGGR also oversees activities on federal lands where the underlying mineral resource is privately owned; however, these lands are extremely rare, and thus not further discussed herein.

other activities. DOGGR's programs include: well permitting and testing; safety inspections; oversight of production and injection projects; environmental lease inspections; idle-well testing; inspecting oilfield tanks, pipelines, and sumps; hazardous and orphan well plugging and abandonment contracts; and subsidence monitoring.

3. Bonding/Financial Commitments

Both the SLC and DOGGR (through the State Oil and Gas Supervisor, who heads DOGGR) may require bonds or other financial surety from operators. These two are discussed separately below.

3.1 Bonding, State Lands Commission

Each oil and gas lease issued by the SLC contains a requirement that:

> "the lessee shall, at the time of execution of the lease, furnish and thereafter maintain a good and sufficient bond in such sum as may be specified by the commission, in favor of the State, guaranteeing faithful performance by the lessee of the terms, covenants, and conditions of the lease and of the provisions of this chapter." – California Public Resources Code Section 6829(d) (Cal. Pub. Res. Code § 6829(d))[5]

This is promulgated in California Code of Regulations Title 14, Section 1906, Guaranty Deposits, (Cal. Code Regs. tit. 14, § 1906) which notes:

> "The Commission may require deposits of either bond, cash or other acceptable security to insure compliance with terms and conditions of bids, leases, contracts, or any other agreements."

What constitutes a "good and sufficient" bond is not defined in regulation. All state offshore oil and gas leases are old, with issuance dates ranging from 1943 to the early 1970s. As such, the bonding amounts contained in the original lease documents are not particularly informative of current state practice.

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[5] Cal. Code Regs. tit. 14, § 2124, Surrender of Leased Premises, notes that, at the expiration of a lease, "the lessee shall remove such structures, fixtures and other things as have been put on the lease by the lessee, all removal costs to be borne by the lessee, subject to the lessee's right to remove his equipment as provided in the statutes." This is done "at the option of the commission and as specified by the commission". Representatives of the SLC communicated to ARCADIS that the state will require removal of structures unless environmental review prevents removal.

Lease terms, including bonding amounts and types, are subject to change over time as described below.

- Lease Terms. Exhibit B of the State Oil and Gas Lease form for negotiated subsurface royalty leases notes: "The State may review, from time to time, the sufficiency of the bond and modify its amount and its terms as it deems necessary to ensure performance by the Lessee of all of the covenants and obligations under this lease."
- During Assignment. Cal. Pub. Res. Code § 6804 notes that "Unless approved by the commission no assignment, transfer or sublease shall be of any effect." The Commission takes advantage of the assignment of leases to insert new conditions or stipulations to the lease, and to modify the bonding amount associated with the lease.

3.1.1 Calculation of New Bonding Amounts

There is no process described in regulation or guidance that SLC uses to determine the new amount of a bond for an offshore lease. In recent years, bond amounts have been increased to approximate the real-world costs to decommission/remove offshore infrastructure. The bond amounts are developed using decommissioning cost estimates as presented in the Minerals Management Service (MMS) report Decommissioning Cost Update for Removing Pacific OCS Region Offshore Oil and Gas Facilities, dated January 2010.[6] SLC staff determine new bond amounts by averaging the decommissioning cost estimates for platforms in federal waters that are similar to platforms in state waters (in terms of water depth and topside weight). They then adjust that average cost to account for inflation and changes in the construction cost index realized since the development of the MMS estimates.[7]

Recognizing that the increased bond amounts could incur some financial difficulties for smaller operators, the SLC has allowed operators a period of time (generally 2 to 3 years) to increase the value of their bond(s) (Meshkati pers. com., July 2, 2014). There is no regulation or guidance related to how the bond is structured; the structure of the bond (e.g., premium amount, and other components) would be determined by the surety company. Similarly, there is no regulation or guidance that links the structure or amount of a bond to the remaining life of a given asset or the financial stability of the operator; these factors, among others, would be considered by a surety company to determine the structure of the bond and whether to issue a bond.

[6] This report is currently being updated, suggesting a 5-year revision schedule.

[7] There is no similar report for the decommissioning of onshore infrastructure. Data from the Idle and Orphan Well Program indicate that the average cost of properly plugging an onshore well is $18,100.

3.1.2 Assignation of Leases

Per the State's Request for Assignment of Oil and Gas Lease form:

> "This assignment shall not release the Assignor from any obligation to the State Lands Commission under the lease, any conditions in the assignment agreement to the contrary notwithstanding."

As such, the original leaseholder retains the obligation to remove improvements and structures and to bear the removal costs regardless of the number of times a lease may be assigned.

Also stated in the form is the following condition for lease assignment:

> "A new bond or bond rider or other security in an amount satisfactory to the Commission will also be required."

The Commission has, in the recent past, allowed an assignor (a large independent firm to whom the lease had been assigned by a major integrated company) to post or carry the requisite bond for the assignee (a smaller independent entity).

SLC staff noted that they conduct due diligence on assignees of state leases, particularly for those that are new to the state or to offshore operations. Per the State's Request for Assignment of Oil and Gas Lease form:

> "If the assignment involves the transfer, in whole or in part, of an operating interest under the State Oil and Gas Lease, the Assignee must provide evidence, satisfactory to the Commission, of its ability to perform the lease operations. This requirement may be fulfilled by submitting certified copies for the preceding two complete fiscal years of each of the following: balance sheet, income statement, statement of changes in financial position and all notes to the financial statements. Also submit resumes of the principal management for the company. For publicly traded companies, a copy of the annual report to the Securities and Exchange Commission on Form 10-K may be substituted for the preceding material."

In addition, SLC staff gather publically available information regarding the environmental performance of the assignee in other jurisdictions and the other decommissioning, removal, and restoration (DR&R) liabilities of the assignee.

3.2 Bonding, Division of Oil, Gas, and Geothermal Resources

The DOGGR requires that active wells and idle wells be bonded; the Division may also require "end-of-life" bonds for wells and other infrastructure. These are discussed below.

3.2.1 Active Wells

The DOGGR requires that a bond be posted prior to the drilling, re-drilling, deepening, or in any operation permanently altering the casing of onshore wells (Cal. Pub. Res. Code §§ 3204 and 3205). An individual indemnity bond may be filed for a single well, or a blanket indemnity bond may be filed to cover a number of wells.[8] These sections of the California Public Resources Code were amended in 2013 to increase the bonding amounts; the amendments went into effect January 1, 2014. Table 3.2-1 presents the previous and current bonding amounts.

Table 3.2-1 Past and Current Bonding Amounts for Onshore and Offshore Wells

Infrastructure Description	Previous Bonding Amount	Current Bonding Amount
Single well less than 5,000 feet deep	$15,000	$25,000
Single well 5,001 to 9,999 feet deep	$20,000	$25,000
Single well 10,000+ feet deep	$30,000	$40,000
50 or fewer wells, not including idle well bond	$100,000	$200,000
50+ wells, not including idle well bond	$250,000	$400,000
1+ wells, including idle well bond	$1,000,000	$2,000,000
1+ offshore wells	$250,000	$1,000,000

Notes:
Bond amounts have been changed infrequently; the “previous bonding amounts” presented above went into effect January 1, 1999.
Operators are provided 2 years to increase the value of existing blanket bonds (Cal. Pub. Res. Code § 3205(b)).
Sources: Cal. Pub. Res. Code §§ 3204 and 3205

The statutory changes in 2013 also limit the use of blanket indemnity bonds to operators of 20 or more wells. Those operators with fewer than 20 wells must increase the value of their current blanket indemnity bond to reflect the amount required for individual indemnity bonds. Previously, a blanket indemnity bond could be used for two or more wells.

In addition to the bonding requirements contained in Table 3.2-1, the operator of an offshore well must post a bond in an amount determined by the State Oil and Gas Supervisor to cover the full costs of plugging and abandoning all of the operator’s wells. This amount can be adjusted by the Supervisor no more than once every 3 years. (Cal. Pub. Res. Code § 3205.1)

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8 A blanked indemnity bond is an indemnity bond issued to cover multiple activities or pieces of infrastructure.

3.2.2 Idle Wells

DOGGR requires that an operator of any idle well[9] not covered under a bond provided under Cal. Pub. Res. Code § 3204(c) (see "1+ wells, including idle well bond" in Table 3.2-1) shall do one of the following:

- Submit an annual fee for each idle well equal to the sum of the following:
  - $100 for each idle well that has been idle for less than 10 years
  - $250 for each idle well that has been idle for 10 to 15 years
  - $500 for each idle well that has been idle for more than 15 years (Cal. Pub. Res. Code § 3206(a)(1))
- Provide an escrow account of $5,000 for each idle well; monies to be used by the Supervisor to properly plug and abandon deserted wells. The operator shall fund the escrow account at the rate of at least $500 per well per year, and the escrow account shall be fully funded within 10 years of the date the well is idled (Cal. Pub. Res. Code § 3206(a)(2)).
- File with the Supervisor an indemnity bond in the amount of $5,000 for each idle well (Cal. Pub. Res. Code § 3206(a)(3)).

The amounts of the idle well fees presented above have not changed since 1998. Funds collected under Cal. Pub. Res. Code § 3206 are deposited in the Hazardous and Idle-Deserted Well Abatement Fund. The fund currently has a balance of $734,000 (California Department of Finance 2014).

3.2.3 End-of-Life Bonds

The Supervisor may order a "life-of-well" or "life-of-production facility" bond for an operator who has a history of violating the California Public Resources Code and regulations promulgated thereunder, or for an operator who has outstanding liabilities to the state associated with the well or production facility.

A "life-of-well" bond is to be set in the "amount to cover the cost to properly plug and abandon each well, including site restoration." This amount is to be estimated by the Supervisor as the "cost to plug and abandon based on the wells condition, total depth, required abandonment operations, site restoration prescribed by regulation, and similar well abandonments within the field or lease."

A "life-of-production facility" bond is to be set, in part, in the amount necessary "to cover the costs to decommission each production facility." This amount is to be estimated by the Supervisor based on "the number and volume of tanks, the estimated volume and types of fluids in the tanks, attendant facility

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[9] "Idle well" means any well that has not produced oil or natural gas or has not been used for injection for 6 consecutive months of continuous operation during the last 5 or more years. An idle well does not include an active observation well (Cal. Pub. Res. Code § 3008(d)).

equipment and stored materials onsite, the cost of similar facility decommissioning and removal projects, and any estimates received from licensed demolition contractors."

The amounts of these bonds are reviewed annually and may be adjusted (Cal. Code Regs. tit. 14, § 1722.8).

3.2.4 Acceptable Bond Types

An indemnity bond executed by a surety company authorized by the California Department of Insurance to do business in the state, or a cash bond (check, certificate of deposit, investment certificate, share, or passbook account opened in the name of the DOGGR) are acceptable bonding mechanisms.

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STATE REPORT—COLORADO

1. Background and History

The State of Colorado ranked ninth in the nation in crude oil production in 2013 and sixth in natural gas production in 2012. Resource production is steadily increasing with the use of horizontal drilling and hydraulic fracturing technologies. Substantial new production is coming from the Niobrara Shale formation. Industry estimates of retrievable oil in the Niobrara currently exceed two billion barrels. From 2007 to 2012, crude oil production in Colorado rose 89 percent, and marketed natural gas production rose 38 percent (USEIA 2014).

Colorado is among the major natural gas-producing states in the nation, and output has doubled over the past decade. Historically, the San Juan Basin, which also underlies part of New Mexico, was Colorado’s largest natural gas-producing region, but production has grown in the Denver-Julesberg Basin in the northeast and in the Piceance Basin in the west. The decline in natural gas prices has caused oil and gas activity to move from the mainly dry gas Piceance Basin to areas that also produce crude oil and natural gas liquids. Colorado is home to nine of the nation’s 100 largest natural gas fields (USEIA 2014).

The State of Colorado has significant estimated recoverable bituminous, sub-bituminous, and lignite coal reserves. Colorado had 12 coal mines that produced a total of 24,173,280 tons in 2013 (CDRMS 2013). Coal in Colorado is produced from underground and surface mines, which are primarily in the Green River, Uinta, and San Juan basins. In Colorado, almost one half of coal mined for domestic consumption is used for power generation (USEIA 2014).

2. Regulatory Structure

The State Board of Land Commissioners (also known as the State Land Board [SLB]) has jurisdiction and management control over public and private lands of the state. Generally, these state lands include all ungranted sovereign lands (lands lying below tidal and navigable waters), school lands (lands granted by Congress for the purpose of funding a public school system), swamp and overflowed lands, and some proprietary lands. The state holds the mineral rights to these lands, and the SLB ensures compliance with oil and gas lease terms. The SLB and the Colorado Oil and Gas Conservation Commission (COGCC) are responsible for the management and administration of oil and gas resources contained on these state lands. The U.S. Bureau of Land Management (BLM) is responsible for overseeing oil and gas activities on federal trust lands and ensuring compliance with oil and gas lease terms (BLM 2014). Furthermore, the COGCC is responsible for the management and administration of oil and gas resources on private lands. Ultimately, the tangible oil and gas resources are managed by the leaseholders, but the SLB, COGCC, and BLM oversee compliance with oil and gas lease terms.

The Division of Reclamation, Mining and Safety (DRMS) within the Colorado Department of Natural Resources is responsible for overseeing mining activities on all lands within Colorado. The division is composed of the Office of Mined Land Reclamation and the Office of Active and Inactive Mines. The Office of Mined Land Reclamation issues reclamation permits from either the Minerals Program or the Coal Program. Together, these two programs regulate mining and reclamation activities at coal, metal, aggregate, and other minerals mines. Their primary objective is to review mining and reclamation permit applications and to inspect mining operations to make sure that reclamation plans are being followed. The Office of Active and Inactive Mines reclaims and safeguards abandoned mine sites that are dangerous and create environmental hazards. The program also provides safety training for mine operators and employees.

3. Bonding/Financial Commitments

The State Board of Land Commissioners, the COGCC, and the DRMS may require bonds or other financial surety from operators. These are discussed separately below.

3.1 Bonding, State Board of Land Commissioners, Department of Natural Resources

The SLB Commissioners was established in 1876 to manage more than three million acres of land and four million acres of mineral rights that the federal government gave to Colorado to generate revenue for public education and some of the state's institutions. The SLB's Resource Extraction group manages the exploration and development of coal, oil and gas, and other solid minerals. It oversees and evaluates nonrenewable resources, manages all mineral leases, administers quarterly oil and gas lease sales, processes mineral royalty revenue, and ensures that the state is compensated for its resources. The Royalty Accounting Unit of the Minerals Section processes mineral royalty revenue and executes related audit and compliance programs. The Leasing Unit is responsible for leasing and developing the state's landholdings for energy and mineral development. Oil and gas leases issued by the SLB are valid for a primary term of 5 years. The leases can be held indefinitely as long as oil and/or gas is produced in paying quantities, and the lease does not violate its land development obligations (SLB 2014a).

3.1.1 Oil and Gas Bonding Amounts

Each drilling permit issued by the SLB has a requirement that:

> "A reclamation bond is required on all wells drilled on State lands. Bonds may be submitted in the form of a surety bond, a certificate of deposit, an irrevocable bank letter of credit or cash bond in the appropriate amount."

Surface restoration bonding requirements for wells drilled on leases issued by the SLB include:

Surety Bond:

- $5,000 for a single well surety bond
- $15,000 for a lease surety bond that will cover all wells drilled on one lease
- $25,000 for a blanket surety bond that will cover all wells drilled on state leases by the bonded principal.

Cash (no interest will be paid to depositor):

- $5,000 for single well
- $15,000 for entire lease
- $25,000 for blanket

Certificate of Deposit (SLB is beneficiary. Original CD is held by SLB). Note: Certificates of Deposit must be placed in an institution that is compliant with the Colorado Public Deposit Protection Act (PDPA):

- $5,000 for single well
- $15,000 for entire lease
- $25,000 for blanket

Irrevocable Bank Letter of Credit:

- $5,000 to $25,000

An oil and gas lease may be terminated at any time with the written consent of the state; however, all outstanding account balances and reclamation, if applicable, must be reconciled before the restoration bonds are released (SLB 2014b).

3.2 Bonding, Colorado Oil and Gas Conservation Commission

The COGCC requires financial assurance prior to operations of wells, seismic exploration, centralized waste management facilities, and for gas gathering systems. The types of bonds required by the COGCC include surface bonds, centralized exploration and production (E&P) waste management facility bonds, seismic bonds, soil protection, plugging and abandonment bonds, inactive wells, natural gas gathering, processing and storage facility bonds, and surface facility/structures pertinent to Class II commercial underground injection control well bonds.

The requirements are outlined in the COGCC series 700 rules. The series 700 rules pertain to the provision of financial assurance by operators to ensure the performance of certain obligations imposed by the Oil and Gas Conservation Act, §34-60-106 (3.5), (11), (12) and (17) Colorado Revised Statutes (C.R.S.), as well as the use of the Oil and Gas Conservation and Environmental Response Fund, §34-60-124 C.R.S., as a mechanism to plug and abandon orphan wells, perform orphaned site reclamation and remediation, and to conduct other authorized environmental activities. The series 700 rules apply primarily to state, private, and federal trust lands unless otherwise noted (SLB elected to adopt a different set of values for surface restoration bonds on state lands). The requirements of the 700 series do not apply to situations where assurance has been provided to federal (BLM managed) or Indian agencies for operations regulated solely by such agencies. The 700 series regulations are discussed below.

3.2.1 Surface Bonds

Each drilling permit issued by the COGCC contains an assurance requirement that:

> "Operators shall provide financial assurance to the [Colorado Oil and Gas Conservation] Commission, prior to commencing any operations with heavy equipment, to protect surface owners who are not parties to a lease, surface use or other relevant agreement with the operator from unreasonable crop loss or land damage caused by such operations. Financial assurance for the purpose of surface owner protection shall not be required for operations conducted on state lands when a bond has been filled with the State Board of Land Commissioners."

The COGCC will release the financial assurance liability from a well when the vegetation has recovered to 80 percent of the pre-disturbance coverage (COGCC 2012). Details for surface owner protection assurance policies are outlined in rule 703. The surface bond values outlined by the COGCC are to be used on private and federal trust lands.

The financial assurance required by rule 703 shall be in the amount of:

- $2,000 per well when located on non-irrigated land.
- $5,000 per well when located on irrigated land.
- $25,000 for a statewide blanket financial assurance bond.

3.2.2 Centralized Exploration and Production Waste Management Facility Bond

If operators plan on building or constructing a waste management facility associated with exploration and production, a surety bond must first be in place prior to beginning construction.

> "An operator which makes application for an offsite, centralized E&P waste management facility shall, upon approval and prior to commencing construction, provide to the COGCC financial

> assurance in an amount equal to the estimated cost necessary to ensure the proper reclamation, closure, and abandonment of such facility as set forth in Rule 908.g [(E&P closure plan)] or in an amount voluntarily agreed to with the Director, or in an amount to be determined by order of the [COGCC]. Operators of centralized E&P waste management facilities permitted prior to May 1, 2009 on federal land and April 1, 2009 for all other land shall, by July 1, 2009 comply with Rule 908.g and this Rule (704). This does not apply to underground injection wells and multi-well pits."

Details for the E&P waste management bond requirements are outlined in Rule 704 (COGCC 2014).

3.2.3 Seismic Operation Bonds

Each seismic permit issued by the COGCC contains an assurance requirement that:

> "Any operator submitting a Notice of Intent to Conduct Seismic Operations shall, prior to commencing such operations, provide financial assurance to the COGCC in the amount of a $25,000 statewide blanket financial assurance to ensure the proper plugging and abandonment of any shot holes and any necessary surface reclamation"

Details for the seismic bond requirements are outlined in Rule 705 (COGCC 2014).

3.2.4 Soil Protection, Plugging, and Abandonment Bonds

Each drilling permit issued by the COGCC contains an assurance requirement that:

> "Prior to commencing the drilling of a well, an operator shall provide financial assurance to the Commission to ensure the protection of the soil, the proper plugging and abandonment of the well, and the reclamation of the site in accordance with the Series 300 drilling regulations, the 900 series of E&P waste management, the 1000 series of reclamation regulations, and the 1100 series of flow line regulations."

Details for the abandonment bond requirements are outlined in Rule 706 and are as follows:

- $10,000 per well for wells less than 3,000 ft in total measured depth.
- $20,000 per well for wells greater than or equal to 3,000 ft in total measured depth.
- In lieu of the per well amounts, an operator may submit statewide blanket financial assurance in the amount of $60,000 for the drilling and operation of fewer than 100 wells.
- In lieu of the per well amounts, an operator may submit statewide blanket financial assurance in the amount of $100,000 for the drilling and operation of 100 or more wells.

All oil and gas wells, excluding domestic gas wells, with financial assurance posted prior to May 1, 2009 for federal land and April 1, 2009 for all other land, as well as all new domestic gas wells, must have financial assurances in compliance with the above criteria set in place on July 1, 2009. An operator may seek a variance from these financial assurance requirements under appropriate circumstances (Rule 502.b[1]. – COGCC).Inactive Wells

Each drilling permit issued by the COGCC contains an assurance requirement that:

> "To the extent that an operator's inactive well count exceeds such operator's financial assurance amount divided by $10,000 for inactive wells less than 3,000 feet in total measured depth or $20,000 for inactive wells greater than 3,000 feet, such additional wells are considered to be excess inactive wells. For each excess inactive well, the operator's financial assurance shall be increased by $10,000 for wells less than 3,000 feet or $20,000 for inactive wells greater than or equal to 3,000 feet in total measured depth. This requirement shall be modified or waived if the Commission approves a plan submitted by the operator for reducing such additional financial assurance requirement, for returning wells to production in a timely manner, or for plugging and abandoning such wells on an acceptable schedule."

Details for the inactive well bond requirements are outlined in Rule 707 (COGCC 2014).

3.2.5 General Liability Insurance

The COGCC has set forth a minimum requirement that operators shall maintain general liability for property damage and bodily injury to third parties of at least $1,000,000 per occurrence. Furthermore, the COGCC will be listed as certificate holder on the certificate of insurance. Details for the additional insurance requirement are outlined in Rule 708 (COGCC 2014).

3.2.6 Life of Bonds – Financial Assurance

All permits issued by the COGCC contain an assurance requirement that:

> "All financial assurance provided to the [COGCC] pursuant to the series [700 rules] shall remain in-place until such time as the director determines that an operator has complied with the statutory obligations described herein, or until such time as the Director determines that a successor-in-interest has filed satisfactory replacement assurance, at which time the Director shall provide written approval for release of such financial assurance. Whenever an operator fails to fulfill any statutory obligation described herein, and the Commission undertakes to expend funds to remedy the situation, the Director shall make application to the Commission for an order calling or foreclosing the operator's financial assurance."

If an operator's assurance is foreclosed, the amount will be deposited into the Oil and Gas Conservation and Environmental Response Fund, and an overhead recovery fee of 10 percent of the funds spent by the Director as costs will be charged against any excess assurance. If the well or lease rights are sold or transferred, the bond will remain until the director determines that a successor-in-interest has filed satisfactory replacement assurance. An operator registration form will not be approved when wells are sold or transferred until the successor operator has filed satisfactory financial assurance of the series 700 rules. As mentioned previously in Section 3.2.1, surface bonds may be released when vegetation has reached 80 percent of the pre-disturbance coverage.

The details on the life of financial assurance are provided in Rule 709 (COGCC 2014).

3.2.7 Oil and Gas Conservation and Environmental Response Fund

In the case of orphaned wells and sites, the COGCC states in Rule 701 that:

> "The Commission shall ensure that the two-year average of the unobligated portion of the Oil and Gas Conservation and Environmental Response Fund is maintained at a level of approximately, but not to exceed, four million dollars, and that there is an adequate balance in the fund to address environmental response needs, which may be used in accordance with the [Oil and Gas Conservation] Act and Rule 701."

Rule 701 outlines the scope of the COGCC assurance regulations, and in the case of the Response Fund, states that the fund will be used:

> "as a mechanism to plug and abandon orphan wells, perform orphaned site reclamation and remediation, and to conduct other authorized environmental activities."

The details of the Oil and Gas Conservation and Environmental Response Fund are provided in Rule 710 (COGCC 2014).

3.2.8 Natural Gas Gathering, Natural Gas Processing, and Underground Natural Gas Storage Facility Bonds

Each drilling permit issued by the COGCC contains an assurance requirement that:

> "Operators of Natural gas gathering, natural gas processing, or underground natural gas storage facilities shall be required to provide statewide [blanket assurance (to comply with 900 rules)] of $50,000, or in an amount voluntarily agreed to with the Director, or in an amount agreed upon by the Commission. Operators of small systems gathering or processing less than 5 [million metric standard cubic feet per day] MMSCFD may provide individual financial assurance in the amount of $5,000."

Rule 711 applies to any mineral or natural resource extracted from wells operated within Colorado (ARCADIS 2014). Details for the bond requirements are outlined in rule 711 (COGCC 2014).

3.2.9 Surface Facilities and Structures Pertinent to Class II Commercial Underground Injection Well Bonds

Each drilling permit issued by the COGCC contains an assurance requirement that:

> "Operators of Class II Commercial Underground Injection Control wells shall be required to provide assurance to comply with the 900-series rules, of $50,000 for each facility, or in an amount voluntarily agreed to with the director, or in an amount agreed upon by the Commission. The financial assurance required by this Rule 712 shall apply to surface facilities and structures appurtenant to the Class II commercial injection well and used prior to the disposal of E&P wastes into such well and shall be in place by July 1, 2009. [The assurance requirements for the abandonment of Class II commercial wells are specified in Rule 706.]"

Details for the bond requirements are outlined in rule 712 (COGCC 2014).

3.2.10 Acceptable Bond Types

Operators are required to provide financial assurance to the COGCC to demonstrate that they are capable of fulfilling the obligations imposed by the Colorado Oil and Gas Conservation (OGC) Act. Except under special circumstances, a surety bond, in a form and from a company acceptable to the COGCC, is an approved method of providing financial assurance. Any other method of assurance identified in §34-60-106(13), C.R.S. will be submitted for approval, shall be equivalent to the surety bond amount, and may require detailed Commission review on an ongoing basis (COGCC 2014).

3.2.11 Increase of Bond Amounts

Bond amounts may be increased on a case-by-case basis. If the Director believes that the Commission will be burdened with higher cleanup costs based on a particular set of circumstances, then he/she may petition for an increase in initial financial assurance requirements. Rule 702 states:

> "When the director of the COGCC has reasonable cause to believe that the Commission may become burdened with the costs of fulfilling the statutory obligations described herein because an operator has demonstrated a pattern of non-compliance with oil and gas regulations in Colorado or other states, because special geologic, environmental, or operational circumstances exist which make plugging and abandonment of particular wells more costly, or due to other and special and unique circumstances, the Director may petition the Commission for an increase in any individual or blanket financial assurance required in [the 700] series (COGCC 2014)."

The financial assurance requirements outlined by the COGCC were last updated in 2009 and are reviewed as needed by COGCC staff (ARCADIS 2014).

3.3 Bonding, Division of Reclamation, Mining, and Safety

In order to determine bond amounts for mining operations, the DRMS has different procedures for coal mining, construction materials mining, and hard rock mining.

3.3.1 Coal Mining

Each surface coal mining permit issued by the DRMS contains a requirement that:

> "[T]he amount of the bond required for each bonded area shall depend upon the reclamation requirements of the approved permit, shall reflect the probable difficulty of reclamation, giving consideration to such factors as topography, geology of the site, hydrology, and revegetation potential, and shall be determined as part of the proposed decision of the office pursuant to section 34-33-114, and subject to review by the board as provided in section 34-33-119…. The amount of the bond shall be sufficient to assure the completion of the reclamation plan if the work had to be performed by the board in the event of forfeiture… and in no case shall the bond for the entire area under one permit be less than ten thousand dollars." – C.R.S. § 34-33-113(1) (C.R.S. § 34-33-113(1))

Each permit application requires the operator to submit a reclamation plan with a detailed cost estimate. 2 Code of Colorado Regulations (CCR) 407-2, Rule 2.05.4 notes:

> "Each plan shall contain the following information for the proposed permit area, including any roads which are to be removed, or modified for retention as part of the post-mining land use…A detailed estimate of the cost of reclamation of the proposed operations required to be covered by a performance bond with supporting calculations for the estimates."

According to 2 CCR 407-2, Rule 3.02.2, in order to assure sufficiency, the bond amount is based on:

(i) The estimated cost submitted by the applicant

(ii) Any additional estimated costs to the Board, which may arise from applicable public contracting requirements or the need to bring personnel and equipment to the permit area after its abandonment by the permittee to complete the reclamation plan

(iii) All additional estimated costs necessary, expedient, and incident to the satisfactory completion of the requirements of C.R.S. § 34-33-113(1)

(iv) Such other cost information as may be required by or available to the DRMS.

The bonding amounts and types are subject to change over time:

- C.R.S. § 34-33-113(5) notes: "The amount of the bond or deposit required and the terms of each acceptance of the applicant's bond shall be adjusted by the office from time to time for good cause as affected land acreages are increased or decreased or when the cost of future reclamation changes."

3.3.2 Materials and Hard Rock Mining

C.R.S. § 34-32.5-117(4), the Construction Materials Section, and C.R.S. § 34-32-117(4), the Hardrock Section note: "The board shall prescribe the amount and duration of financial warranties, taking into account the nature, extent, and duration of the proposed mining operation and the magnitude, type and estimated cost of planned reclamation."

Each construction materials mining and hard rock mining permit issued by the DRMS contains a requirement that[10]:

> "In a [any] single year during the life of a permit the amount of required financial warranties shall not exceed the estimated cost of fully reclaiming all lands to be affected in such [said] year plus all lands affected in previous permit years and not yet fully reclaimed. For purposes of this paragraph, reclamation costs shall be computed with reference to current reclamation costs. [The amount of the] financial warranty shall be sufficient to assure the completion of reclamation of affected lands if, because of forfeiture, the office has to complete such reclamation and [if the office has to complete such reclamation due to forfeiture. Such financial warranty…] shall include an additional amount equal to five percent of the amount of the financial warranty to defray administrative costs incurred by the office in conducting the reclamation." - C.R.S. § 34-32.5-117(4) and C.R.S. § 34-32-117(4).

The bonding amounts and types are subject to change over time as follows:

- C.R.S. § 34-32.5-117(4) and C.R.S. § 34-32-117(4) note: "The board may: From time to time for good cause shown, increase or decrease the amount and duration of a required financial warranty."
- The 2 CCR 407-4, Rule 4.2.1, dictates that "The Office or Board may, in its discretion, review any Financial Warranty for adequacy at any time."

[10] Differences between Construction Materials and Hard Rock Acts noted in brackets.

3.3.3 Estimating Bonding Amounts

For regular operation permit applications, "all information necessary to calculate the costs of reclamation must be submitted and broken down into the various major phases of reclamation. The information provided by the Operator/Applicant must be sufficient to calculate the cost of reclamation that would be incurred by the state." Regular Operation applies to any mining operation affecting 10 acres or more, or extracting 70,000 tons or more of mineral, overburden, or combination thereof per calendar year (2 CCR 407-4, Rule 6.4.12).

All Limited Impact permit applications must provide an estimate of the actual costs to reclaim the site based on what it would cost the State of Colorado employing an independent contractor to complete reclamation. Limited Impact Operation applies to any mining operation which affects less than ten acres for the life of the mine, extracts less than 70,000 tons of mineral, overburden, or combination thereof per calendar year, and is not an in situ leach mining operation.

The DRMS has its own proprietary software for the calculation of reclamation cost estimates in order to confirm the cost estimates in the permit applications and determine the bond liability. After the direct costs have been estimated, an additional maximum 18.5 percent of that total may be added, which includes private contract, typical overhead costs. This additional cost is required to cover indirect costs that an independent contractor would incur when performing reclamation of the site. Five percent additional cost is added to cover administration cost in the event of bond forfeiture and permit cancellation (2 CCR 407-4, Rule 6.3.4).

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STATE REPORT—PENNSYLVANIA

1. Background and History

The first commercially successful oil production well in the world was drilled in Pennsylvania in 1859 and by the late 1800s, Pennsylvania was the nation's lead producer of oil, producing about 58 percent of the crude oil in the country (approximately 31 million barrels/year) (PADEP 2014a). In 2013, nearly five million barrels of oil were produced in Pennsylvania. While the volume of oil produced in the state has diminished since the peak in the late 1800s, conventional oil reserves still support a viable oil industry. It is estimated that more than 350,000 oil and gas wells have been drilled in the state since commercial production first began.

Natural gas has been produced in Pennsylvania for more than a century. In recent times, the state has experienced a resurgence in natural gas production due to advances in drilling and geotechnical mapping technologies. Previously inaccessible gas reserves, such as those found in the Marcellus Shale, are now accessible due to technological advances like horizontal drilling and hydraulic fracturing. Pennsylvania is the second largest producer of natural gas in the nation, and in 2013, more than three trillion cubic feet of natural gas were produced (PADEP 2014a).

The oil and gas regulatory approach developed and implemented in Pennsylvania to protect public and environmental health while facilitating optimal resource development has been recognized nationally and internationally, and it has served as model to other states' agencies (PADEP 2014a).

2. Regulatory Structure

In Pennsylvania, oil and gas exploration is regulated by oil and gas laws and environmental protection laws. Oil and gas laws include: the Oil and Gas Act, Coal and Gas Resource Coordination Act, and the Oil and Gas Conservation Law. Environmental protection laws include: the Clean Streams Law, the Dam Safety and Encroachments Act, Solid Waste Management Act, Water Resources Planning Act, and the Community Right to Know Act. The state does not regulate lease agreements between property owners and producers.

The 1984 Oil and Gas Act (58 P.S. §601.101 et seq.) required permitting of new oil and gas wells by the state prior to commencement of drilling, and the registration of existing wells, which were not previously permitted. The Act also established bonding requirements for permitted wells. The Oil and Gas Management Program, administered by the PADEP, is the forum employed by the state for developing and regulating oil and gas well permitting, bonding, and registration and regulating environmental mandates for drilling operations, waste disposal, cementing and casing of wells, and well plugging upon abandonment (PADEP 2007).

The 2012 Oil and Gas Act (Act 13), which was signed into law by Governor Corbette on February 14, 2012, was the first major overhaul of Pennsylvania oil and gas regulations since the Oil and Gas Act of 1984. Act 13 (PADEP 2014b):

- Established surcharges to fund orphaned and abandoned well plugging program administered by the State (§3271)
- Charged PADEP with developing rulemaking to amend existing oil and gas laws to address surface-related activities for oil and gas, including site restoration
- Established an "impact fee," which is a fee for unconventional gas wells that is distributed to state and local governments and administered by the Pennsylvania Public Utility Commission (PUC 2013a).

Act 13 contains provisions regarding the distribution and use of monies collected as part of the "impact fee." Local governments that have passed ordinances may impose impact fees for unconventional wells located within their jurisdictional to cover the impacts associated with drilling. Unconventional well producers within the state must pay the fee annually, which is determined by a multi-year fee schedule based on the average price of natural gas. The fee may be adjusted upward to reflect changes in the Consumer Price Index if the number of unconventional gas wells in a given year exceeds the total number of wells in the prior year. The Pennsylvania PUC is responsible for administering the collection and disbursement of the impact fee (PUC 2013b).

According to Act 13, the PUC "will impose a fee for each horizontal unconventional gas well from year one to year 15 based upon the average annual price of natural gas in the calendar year when the fee is imposed. Vertical unconventional gas wells pay 20 percent of the established horizontal well fee for calendar years in which the well is producing more than 90,000 cubic feet of gas per day during any calendar month. Under the Act, wells that do not produce natural gas in quantities greater than those of a stripper well (90,000 cubic feet per day) do not pay the fee" (PUC 2013b).

2.1 Proposed Regulatory Changes

Currently, regulatory changes to state laws that govern oil and gas well construction and operation (Chapter 78 of Pennsylvania Code) are proposed and undergoing public and technical comment periods. The changes proposed pertain to the regulation of oil and gas surface activities, and they are broad-reaching. The development of the proposed regulatory changes is being overseen by the Environmental Quality Board.

The proposed changes are categorized by PADEP as: permitting, abandoned well identification, waste management at well sites, and off-well site issues (Legere 2014). Permitting changes proposed would encompass requirements of oil and gas developers to consider public natural resources protection strategies and other considerations raised by the public, but it could not block access to the oil and gas resources. Under the proposed changes, prior to new oil and gas well development using hydraulic fracturing techniques, operators would be required to map potential abandoned wells within 1,000 feet of the new well bore location. Operators would also be required to monitor any old wells within this range and plug them if they are altered in the hydraulic fracturing of the new well. Proposed changes related to well site waste management and off-site well issues focus on increased protection measure requirements operators would need to implement to protect surface and groundwater resources from spills and transport infrastructure like pipelines and roads.

Other Pennsylvania laws affecting oil and gas well plugging and restoration activities include: Clean Streams Law, Solid Waste Management Act, Act 2, and the Dam Safety Encroachments Act

2.2 Regulatory Administration

The PADEP is the primary state agency responsible for oversight and regulation of the oil and gas industry in the state. The PADEP is charged with issuing permits for oil and gas well construction and operation, conducting inspections, and overseeing the state's well plugging program for abandoned or orphaned wells (PADEP 2014b).

The well plugging programming was implemented as a result of the Oil and Gas Act of 1984 to regulate the proper plugging of wells. In recent years, the promulgation of oil and gas regulations requires operators to post bonds with the PADEP to facilitate proper well plugging and restoration after production has ceased (PADEP 2014b).

In 2011, the Office of Oil and Gas Management (OOGM) was established within the PADEP as a result of the Department's reorganization. The OOGM consists of two bureaus: the Bureau of Oil and Gas Planning and Program Management and the Bureau of District Oil and Gas Operations. The Bureau of Oil and Gas Planning and Program Management is responsible for program administration and developing policy and regulations. There are three divisions of this Bureau: 1) Well Development and Surface Activities, 2) Well Plugging and Sub-Surface Activities, and 3) Compliance and Data Management (PADEP 2014b).

The Pennsylvania Department of Conservation and Natural Resources (DCNR) has jurisdiction and management control over public lands of the state. For some of these lands, the state holds the mineral rights (unsevered) and in other cases the state does not (severed). The DCNR's Bureau of Forestry is responsible for the management and administration of oil and gas resources contained on these state lands.

3. Bonding/Financial Commitments

Bonds are used as financial incentives to ensure that operators adequately perform drilling and address potential water supply problems arising from drilling operations, well reclamation, and plugging upon abandonment. Operators of oil and gas wells drilled after April 17, 1985 in Pennsylvania must be bonded by the state (Oil and Gas Act 1984).

Pennsylvania requires that oil and gas operators maintain financial assurances for certain oil and gas operations pursuant to 58 Pa.C.S. § 3225.

> "§ 3225 Bonding.
>
> (a) General rule.--The following shall apply:
>
> (1) Except as provided in subsection (d), upon filing an application for a well permit and before continuing to operate an oil or gas well, the owner or operator of the well shall file with the department a bond covering the well and well site on a form to be prescribed and furnished by the department. A bond filed with an application for a well permit shall be payable to the Commonwealth and conditioned upon the operator's faithful performance of all drilling, water supply replacement, restoration and plugging requirements of this chapter. A bond for a well in existence on April 18, 1985, shall be payable to the Commonwealth and conditioned upon the operator's faithful performance of all water supply replacement, restoration and plugging requirements of this chapter. The amount of the bond required shall be in the following amounts and may be adjusted by the Environmental Quality Board every two years to reflect the projected costs to the Commonwealth of plugging the well:"

Section 3225 also describes varying bond amounts, which are based on the number of wells and the total depth of the well bores. These bonds are described in Section 3.1.

In addition, Act 87, which became effective in July 2012, affected bonding requirements for conventional oil and gas wells drilled in Pennsylvania.

> "Act 87, Section 1606-E. Conventional oil and gas well bonding.
>
> (a) Requirement.—Notwithstanding 58 Pa.C.S. § 3225(a)(1) (relating to bonding), the bond amount for conventional oil or gas wells shall be $2,500 per well or a blanket bond of $25,000. The Environmental Quality Board shall undertake a review of the existing bond requirements for conventional oil and gas wells. Nothing in this section shall be construed to alter or repeal section 1934-A of the act of April 9, 1929 (P.L.177, No.175), known as The Administrative Code of 1929.

3.1 Bonding, Department of Conservation and Natural Resources

3.1.1 Calculation of New Bonding Amounts

Bond amounts may be adjusted every 2 years by the Environmental Quality Board per §3225 of Act 13 (Act 13 is also known as the 2012 Gas Act).

3.2 Bonding, Bureau of Oil and Gas Management

The Oil and Gas Act of 1984 requires oil and gas operators to post a bond with the PADEP prior to drilling. Bonded monies are released 1 year after the PADEP declares regulatory requirements associated with wells. Prior to April 17 1985, the state did not require bonding prior to drilling oil and gas wells.

3.2.1 Active Wells

Bonds required for active wells, drilled after April 17, 1985, aim to cover costs associated with well plugging, abandonment, and restoration. Current bond amounts required by the state vary based on well type (conventional vs. non-conventional) and well bore depth for unconventional wells.

Bonding amounts in Pennsylvania changed as a result of the passage of Act 13 in 2012 (PADEP 2014a). Act 13 increased well bonding requirements, which had been $2,500 per well or $25,000 for a blanket bond. Bond amounts are now established based on well bore length and number of wells operated, as follows.

- For wells with total well bore lengths less than 6,000 feet:
  - For up to 50 wells - $4,000/well not to exceed $35,000
  - For 51 to 150 wells - $35,000 plus $4,000/well not to exceed $60,000
  - For 151 to 250 wells - $60,000 plus $4,000/well not to exceed $100,000
  - For more than 250 wells - $100,000 plus $4,000/well not to exceed $250,000
- For wells with total well bore lengths 6,000 feet or deeper:
  - For up to 25 wells - $10,000/well not to exceed $140,000
  - For 26 to 50 wells - $140,000 plus $10,000/well not to exceed $290,000
  - For 51 to 150 wells - $290,000 plus $10,000/well not to exceed $430,000
  - For more than 150 wells - $430,000 plus $10,000/well not to exceed $600,000

A summary of the bond amounts previously and currently required in Pennsylvania for oil and gas wells is provided in Table 3.2-1.

Table 3.2-1 Past and Current Bonding Amounts for Onshore Wells

Infrastructure Description	Previous Bonding Amount[1]	Current Bonding Amount
Single conventional well	$2,500	$2,500
Blanket bond for conventional wells	$25,000	$25,000
1 to 50 unconventional wells, each less than 6,000 feet deep.	$2,500. Same as that required for single conventional well.	$4,000 per well. Bond maximum of $35,000
51 to 150 unconventional wells, each less than 6,000 feet deep	$25,000 Same as blanket bond required for conventional wells	$35,000 + ($4,000/per well for each well in excess of 50 wells). Bond maximum $60,000
151 to 250 unconventional wells, each less than 6,000 feet deep	$25,000 Same as blanket bond required for conventional wells	$60,000 + ($4,000/per well for each well in excess of 150 wells). Bond maximum $60,000
251+ unconventional wells, each less than 6,000 feet deep	$25,000 Same as blanket bond required for conventional wells	$100,000 + ($4,000/per well for each well in excess of 250 wells). Bond maximum $100,000
1 to 25 unconventional wells, each greater than 6,000 feet deep.	$2,500. Same as that required for single conventional well.	$10,000 per well. Bond maximum of $140,000
26 to 50 unconventional wells, each greater than 6,000 feet deep	$2,500. Same as that required for single conventional well.	$140,000 + ($10,000/per well for each well in excess of 25 wells). Bond maximum $290,000
51 to 150 unconventional wells, each greater than 6,000 feet deep	$25,000 Same as blanket bond required for conventional wells	$290,000 + ($4,000/per well for each well in excess of 50 wells). Bond maximum $430,000
151+ unconventional wells, each greater than 6,000 feet deep	$25,000 Same as blanket bond required for conventional wells	$430,000 + ($10,000/per well for each well in excess of 150 wells). Bond maximum $600,000

Notes:

1 Applies to oil and gas wells drilled in after April 17, 1985 and before 2012.

Sources: Pennsylvania Title 58, III (B) Section 3225: Bonding and Act 87, Section 1606-E

3.2.1.1 Wells on State Forest Lands

Pennsylvania includes a condition in all of its lease agreements for drilling in state forests that requires operators to submit additional individual well bonds. The dollar amount required scales with the measured depth, so operators in state forests are required to post bonds of $10,000 to 100,000 per well drilled (DCNR 2010).

Financial security requirements by the State are described in the “Oil and Gas Lease for State Forest Lands” (Form M-O&G [11-09], Contract No.M-110001-15 §16).

> “16. FINANCIAL SECURITY
>
> 16.01 BONUS PAYMENT SECURITY - Lessee shall provide the Department with an irrevocable letter of credit in a form acceptable to Department in the amount of ten percent (10%) of the total

bonus rental payment due under Section 3.01 of this lease. The Department shall consider security consistent with this requirement provided to the Department by Lessee at the time Lessee submits its bonus bid to satisfy this requirement upon the Effective Date of the Lease.

16.02 PERFORMANCE SECURITY – Not later than March 12, 2010 Lessee shall provide Department with financial security in a form acceptable to Department (i.e., surety bond, irrevocable letter of credit with evergreen provisions, bank certificate of deposit, etc.) for the principal sum of TWENTY-FIVE THOUSAND DOLLARS ($25,000.00) conditioned on the faithful performance by Lessee of the covenants of this lease. The performance security shall be further conditioned that, in the event Lessee shall fail to remove its equipment and machinery or properly abandon all wells within one (1) year from the termination of this lease, Commonwealth can execute upon the performance security provided to pay for cost of removal of the equipment and machinery and proper abandonment of the well or wells. In addition, the performance security shall be conditioned in favor of the Commonwealth for all damages that may arise as a result of fires, accidents, pollution, or any other causes brought about by Lessee or Lessee's agents occupying the leased premises and in the use of all State Forest roads off the leased premises.

16.03 WELL PLUGGING SECURITY - Additionally, prior to acquiring any existing well on the leased premises, or upon the Lessee's decision to keep a newly drilled well, Lessee shall provide Department with financial security in a form acceptable to Department (i.e., surety bond, irrevocable letter of credit with evergreen provisions, bank certificate of deposit, etc.) in an amount equal to or exceeding the reasonably expected estimated total cost of plugging the well one (1) year after its completion as a producer or shut-in well. This well plugging security shall remain in effect until the plugging and abandonment of the well has been completed in compliance with applicable state law and the well site has been restored and re-vegetated to the satisfaction of District Forester. The minimum well plugging security coverage per well acceptable to Department as of the date of this agreement is as follows and shall be based on the well's measured depth, regardless of its true vertical depth:

Measured Depth	***Minimum Surety Amount***
Less than 5000'	*$10,000*
5000' to 8500'	*$30,000*
8500' to 10,000'	*$50,000*
10,000' and Deeper	*$100,000*

16.04 Every five (5) years during the term of this lease, and effective on the anniversary of the Effective Date of this lease, new financial security amounts may be instituted at the option of Department by notice in writing from Department to Lessee at least six (6) months prior to the anniversary date. Such new security amounts shall equal the original security amounts set forth in paragraphs 16.02 and 16.03 herein adjusted for inflation so that the security amounts will adequately cover the expected lease obligation costs prevailing at the time of adjustment. The new adjusted security amounts will be rounded off to the nearest ONE THOUSAND DOLLARS ($1,000.00) and will be computed by multiplying the original security amounts set forth herein by a ratio derived from the Producers Price Index for All Commodities using a base of 1982 = 100, compiled and issued monthly by the U.S. Department of Labor's Bureau of Labor Statistics, as follows:

The numerator of the ratio shall be the index number for the item "All Commodities" for the month appearing in the issue of the index most recently preceding the anniversary when the security adjustment is made.

The denominator of the ratio shall be the index number for the item "All Commodities" for the month of September 2009. The parties agree that such index number is 174.6.

If the base period of such index should change to other than 1982 = 100, the aforementioned numerator shall be adjusted by the usual method of linkage of base periods to the end that the ratio shall accomplish its purpose; namely, to adjust the dollar amount of the security or securities for changes in the price level between the date of this agreement and the date when the adjustment is made.

In the event such monthly index should be discontinued, or a new or revised one substituted therefore by the Bureau of Labor Statistics or other agencies of the United States of America, such new or revised or other similar index shall be used for the purpose of computations as described in this paragraph, using such conversion factors or other devices which may be generally recognized or adopted in connection with requirements based on this index."

Well plugging requirements are also specified in the state's oil and gas lease (Contract No.M-110001-15 §33).

"33. PLUGGING

33.01 Lessee shall properly and effectively plug all wells on the leased premises before abandoning, in accordance with the regulations of the Department of Environmental Protection Bureau of Oil and Gas Management and all applicable laws of the Commonwealth."

3.2.2 Orphan Wells

Orphan wells are oil or gas wells for which the owners or legally responsible parties are not known to exist or cannot be identified. The PADEP tracks known orphaned and abandoned wells, although it is estimated there are thousands of wells whose locations remain unknown. According to the PADEP, there are currently more than 8,300 orphaned or abandoned wells on record with the state (PADEP 2014b). A total of almost 3,000 wells have been plugged to date under the purview of the state's Well Plugging Program (PADEP 2014b).

Funding for the well plugging program is realized through surcharges promulgated by the 2012 Oil and Gas Act (§ 3271).

> "§ 3271. Well plugging funds.
>
> (a) Appropriation.--Fines, civil penalties and permit and registration fees collected under this chapter are appropriated to the department to carry out the purposes of this chapter.
>
> (b) Surcharge.--To aid in indemnifying the Commonwealth for the cost of plugging abandoned wells, a $50 surcharge is added to the permit fee established by the department under section 3211 (relating to well permits) for new wells. Money collected as a result of the surcharge shall be paid into a restricted revenue account in the State Treasury to be known as the Abandoned Well Plugging Fund and expended by the department to plug abandoned wells threatening the health and safety of persons or property or pollution of waters of this Commonwealth.
>
> (c) Orphan Well Plugging Fund.--The following shall apply:
>
>> (1) A restricted revenue account to be known as the Orphan Well Plugging Fund is created. A $100 surcharge for wells to be drilled for oil production and a $200 surcharge for wells to be drilled for gas production are added to the permit fee established by the department under section 3211 for new wells. The surcharges shall be placed in the Orphan Well Plugging Fund and expended by the department to plug orphan wells. If an operator rehabilitates a well abandoned by another operator or an orphan well, the permit fee and the surcharge for the well shall be waived.
>>
>> (2) The department shall study its experience in implementing this section and shall report its findings to the Governor and the General Assembly by August 1, 1992. The report shall contain information relating to the balance of the fund, number of wells plugged, number of identified wells eligible for plugging and recommendations as to alternative funding mechanisms.

(3) Expenditures by the department for plugging orphan wells are limited to fees collected under this chapter. No money from the General Fund shall be expended for this purpose."

3.2.3 Acceptable Bond Types

Acceptable bond types in Pennsylvania for oil and gas wells include surety and collateral bonds. These bonds cover plugging, abandonment, and restoration of wells. Bonds do not cover compensation for damage to property or health or full restoration of public infrastructure. The State of Pennsylvania releases operators from assurance 1 year after the well is plugged and reclaimed, which can leave residents, communities, and tax payers financially responsible for long-term damages.

In lieu of corporate surety, the operator may deposit:

- Cash
- Certificates of deposit or automatically irrevocable letters of credit from an authorized bank
- Negotiable bonds - of US gov't or PA, PA Turnpike Commission, General State Authority, State Public School Building, or any PA municipality
- US Treasury Bond at a discount without regular schedule of interest payments to maturity, i.e. "Zero Coupon Bond," which has maturity date ≤10 years

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STATE REPORT—TEXAS

1. Background and History

Texas is the largest oil and gas-producing state in the United States. Historically, oil field development and drilling started in the State of Texas during the second part of the 19th Century. The first economically significant discovery came in 1894 in Navarro County near Corsicana. The first oil refinery in Texas opened in 1898.

The Texas Legislature passed its first statute for oil in 1899, for protection of groundwater, well abandonment, and conservation of natural gas. Subsequently, the legislation was further modified to include fire prevention. In 1917, the Legislature designated oil pipelines as common carriers and gave jurisdiction to the Railroad Commission of Texas (RRC), which was the regulatory agency for the railroad industry (transportation). By 1919, the RRC was also granted jurisdiction over oil and gas production, thereby creating the Oil and Gas Division at the RRC. Regulation did not take hold immediately, and only in the 1930s was RRC able to take a lead regulatory role. Two of its primary responsibilities are the protection of the environment and preservation of individual property rights. The RRC has an extensive history of service to the state.

In 1995, the RRC created the Gas Services Division to reflect the increasing importance of natural gas in Texas and the agency's commitment to enhancing the efficiency of the oil and gas industry. The Gas Services Division enables the RRC to help Texas capitalize on the state's abundant natural gas reserves as markets expand.

There are hundreds of operators, large and small, working today in Texas. The long-term presence of the oil and gas industry and the regulatory oversight by the state agencies make it worthwhile to review the agency-operator regime for Texas.

2. Regulatory Structure

The RRC is the oldest regulatory agency in the State of Texas and has primary regulatory jurisdiction over the oil and natural gas industry, pipeline transporters, natural gas and hazardous liquid pipeline industry, natural gas utilities, the liquefied petroleum gas industry, and coal and uranium surface mining operations. The RRC exercises its statutory responsibilities under provisions of the Texas Constitution, the Texas Natural Resources Code, the Texas Water Code, the Texas Health and Safety Code, the Texas Utilities Code, the Coal and Uranium Surface Mining and Reclamation Acts, and the Pipeline Safety Acts. The RRC also has regulatory and enforcement responsibilities under federal law including the Surface Coal Mining Control and Reclamation Act, the Safe Drinking Water Act, the Pipeline Safety Acts, the Resource Conservation Recovery Act, and the Clean Water Act.

The RRC, through its Oil and Gas Division, regulates the exploration, production, and transportation of oil and natural gas in Texas. Its statutory role is to (1) prevent waste of the state's natural resources, (2) to protect the correlative rights of different interest owners, (3) to prevent pollution, and (4) to provide safety in matters such as hydrogen sulfide. To prevent pollution of the state's surface and groundwater resources, the RRC has an abandoned well plugging and abandoned site remediation program that uses funds raised through industry fees and taxes. Many wells and sites are remediated with these funds when responsible operators cannot be found.

Most oil and gas operations are within the jurisdiction of the RRC including:

- Drilling, operating, producing, fluid injection, transporting, reclaiming, treating, processing, or refining crude oil, gas and products, or geothermal resources and associated minerals
- Discharging, or disposing of oil and gas waste, including hauling salt water for hire by any method other than pipeline
- Operating gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance or re-pressurizing plants, or recycling plants
- Recovering skim oil from a salt water disposal site
- Nominating crude oil
- Operating a directional survey company
- Cleaning a reserve pit
- Operating a pipeline
- Operating as a cementer approved for plugging wells, operating as a cementer cementing casing strings or liners, or operating a well service company performing well stimulation activities, including hydraulic fracturing
- Operating an underground hydrocarbon or natural gas storage facility.

The Texas General Land Office (TGLO) is responsible for management of oil and gas leases on state-owned lands. Generally, these lands include (1) islands, saltwater lakes, bays, inlets, marshes, and reefs owned by the state within tidewater limits; (2) the portion of the Gulf of Mexico within the jurisdiction of the state; (3) all unsold surveyed and unsurveyed public school land; and (4) all land sold with a reservation of minerals to the state under Section 51.054 or 51.086 of the Texas Natural Resource Code Title 2, Subtitle D, Chapter 51, subchapter D, in which the state has retained leasing rights. The TGLO only manages the leases and does not require any financial assurance mechanisms. The financial assurance and regulatory mechanisms are overseen by RRC for both state and private lands, and for operations in state waters.

3. Bonding/Financial Securities

The Texas Administrative Code (TAC) requires that oil and gas producers and operators provide some form of financial assurance. The objective of the RRC's bonding program is to ensure that all entities performing oil and gas-related activities provide or demonstrate adequate financial resources to protect the Texas government from incurring any financial loss. Financial securities are necessary to ensure that owners fully comply with regulatory and lease requirements that include rent, royalties, environmental damage, cleanup and restoration activities, abandonment, and other lease obligations.

3.1 Well Bonding

The RRC requires that any applicant wanting to drill, deepen, plug back, or reenter a well needs to file a financial security with the RRC. These requirements are promulgated in Title 16, Part 1 (Railroad Commission of Texas), Chapter 3 (Oil and Gas Division), § 3.78 (Fees and Financial Security Requirements), which states in part:

> "no organization…shall perform such operations without having on file with the Commission an approved…financial security as required by Texas Natural Resources Code §§91.103 - 91.1091."

The financial security is subject to the conditions that the operator will plug and abandon all wells and control, abate, and clean up pollution associated with the oil and gas operations and activities covered under the required financial security in accordance with applicable state law and permits, rules, and orders of RRC. The amount of the required financial security is discussed further in Section 4 of this report.

3.2 Bonding Requirements

The RRC requires that active wells and idle wells be bonded. The amount of bonding differs depending upon the number of wells, the locations of wells, and the depth of wells as presented in Table 3.3-1.

The amount of a financial security will depend largely on the number of wells an operator owns and the depth of those wells. An operator with only a few shallow wells would be best served by filing an individual performance bond in an amount equal to $2 per foot of total well depth. An operator with many wells would be best served by filing a blanket financial security in the appropriate base amount as shown in Table 3.3-1.

Operators are required to submit financial securities using forms prescribed by RRC at the time of filing an initial organization report as a condition of the issuance of a permit to drill, recomplete, or reenter, upon yearly renewal, or as otherwise required by the RRC.

Table 3.3-1 Bonding Amounts

Infrastructure Description	Bonding Amount
At least one well	$2.00 per each foot
Multiple operations	Base amount as described below or $25,000, whichever is greater
	Base amount
10 or fewer wells	$25,000
10+ wells but fewer than 100 wells	$50,000
100+ wells	$250,000
Bay wells* – additional security amount	$60,000
Offshore wells – additional security amount	$100,000

* Bay wells are generally those wells that are located on a lake, river, stream, canal, estuary, bayou, or other inland navigable waters of the state and which required plugging by means other than conventional land-based methods, including but not limited to the use of a barge, use of a boat, or building a causeway or other access road to bring in the necessary equipment to plug the well, or located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of Gulf of Mexico.

As shown in Table 3.3-1, additional financial security is required for bay and offshore wells that are inactive. Further details are provided below.

- An additional blanket financial security of $60,000 must be posted for each bay well that is not currently producing oil or gas and has not produced within the past 12 months (including injection or disposal wells).
- An additional blanket financial security of $100,000 must be posted for each inactive offshore well that is not producing oil or gas and has not produced oil or gas within the previous 12-month period, including injection and disposal wells.

The Director of the RRC's Division of Oil and Gas may administratively approve a reduction of the additional financial security for bay or offshore wells if an operator provides documentation that it currently has acceptable financial assurance in place to satisfy any financial assurance requirements established by local authorities. The operator must show that the bond or other form of financial assurance can be called on by or assigned to the RRC under the following circumstances:

(v) A well is likely to pollute or is polluting any ground or surface water or is allowing the uncontrolled escape of formation fluids from the strata in which they were originally located; or
(vi) A well is not being maintained in compliance with RRC rules or state law relating to plugging or the prevention or control of pollution; or
(vii) The operator has failed to renew and maintain an organization report filing.

The Director may grant full or partial reduction based on the operator meeting the following criteria:

- The operator has five or fewer bay and offshore wells or at least half of the operator's bay and offshore wells are actively producing oil and natural gas.
- The operator provides to the RRC certification of its net worth from an independent auditor that has employed generally accepted accounting principles to confirm the operator's stated net worth based on the most recently available and independently audited calculation.
- The reduction is less than or equal to the remainder of 25 percent of the operator's certified net worth minus the RRC's estimate of the operator's total plugging liability for all of the operator's active bay and offshore wells.
- None of the operator's wells or operations, including any land-based wells, have been found by RRC staff to be violating or to have violated any RRC rule that resulted in pollution or in any hazard to the health or safety of the public in the last 12 months.

3.3 Types of Acceptable Financial Securities

Four types of financial securities are accepted by the RRC:

- Bond, either individual performance bond or a blanket performance bond. The issuer of any commercial facility bond shall be a corporate surety authorized to do business in Texas. The form of bond shall provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the RRC or its delegate.
- A letter of credit. An irrevocable letter of credit issued on an RRC-approved form, by and drawn on a third-party bank authorized under state or federal law to do business in Texas. The letter of credit will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by the RRC or its authorized delegate.
- A cash deposit filed with the RRC.
- Well-specific plugging insurance policy. A person required to file a bond, letter of credit, or cash deposit who operates one or more wells is considered to have met that requirement for a well if the well bore is included in a well-specific plugging insurance policy. The required criteria for such a policy are as follows:
  - Must be approved by the Texas Department of Insurance
  - Names Texas as the owner and contingent beneficiary of the policy
  - Names a primary beneficiary who agrees to plug the specified well bore
  - Must be fully prepaid and cannot be canceled or surrendered

- Provides that the policy continues in effect until the specified well bore has been plugged
- Provides that benefits will be paid when, but not before, the specified well bore has been plugged in accordance with commission rules in effect at the time of plugging
- Provides benefits that equal the greater of
  - an amount equal to $2 for each foot of well depth, as determined in the manner specified by the commission, for the specified well;
  - if the specified well is a bay well and regardless of whether the well is producing oil or gas, the amount required under commission rules for a bay well that is not producing oil or gas;
  - if the specified well is an offshore well and regardless of whether the well is producing oil or gas, the amount required under commission rules for an offshore well that is not producing oil or gas; or
  - the payment otherwise due under the policy for plugging the well bore.

Any of these financial security types, alone or in combination, can be used to meet the bonding requirements discussed previously.

3.4 Well or Lease Transfer

The RRC shall not approve a transfer of operatorship submitted for any well or lease unless the operator acquiring the well or lease has on file with the RRC a financial security in an amount sufficient to cover both its current operations and the wells or leases being transferred. Any existing financial security covering the well or lease proposed for transfer shall remain in effect and the prior operator of the well remains responsible for compliance with all laws and the RRC rules covering the transferred well until the RRC approves the transfer. A transfer of a well or lease from one entity to another entity under common ownership is also considered a transfer for the purposes of the RRC and will be treated as an ownership transfer. The RRC may approve a transfer of operatorship submitted for any well bore included in a well-specific plugging insurance policy if the transfer meets all other RRC requirements.

3.5 State Managed Well Plugging Program

The State of Texas has maintained a Well Plugging Fund since 1965 to plug and abandon wells that pose a pollution hazard when the responsible owner/operator cannot be located, is insolvent, or is unwilling to plug the well.

Initially, limited funds were appropriated from general revenue for this purpose. In 1983, a new Well Plugging Fund was established and supported primarily by a $100-per-well drilling permit fee, well plugging reimbursements, RRC administrative penalties, Office of the Attorney General civil penalties, and interest on the fund. Since 1988, the fees from Statewide Rule 14(b)(2) well plugging extensions granted by Form W-IX filings also have gone into the fund. A fall in oil prices during the 1980s led to a surge in the number of abandoned, inactive wells. In response, the Texas Legislature enacted a bill in 1991 that replaced the preliminary Well Plugging Fund with a more comprehensive Oil Field Cleanup Fund (OFCU Fund) supported by additional sources of revenue.

In 2002, fees for the OFCU Fund increased substantially to allow for increased well plugging and site remediation. Also, to reduce the number of orphan wells, oil and gas operators were required to transition to universal bonding. In 2004, the Legislature authorized an increase in seal/severance fees to encourage prompt compliance and to enhance the OFCU Fund, and required that all oil and gas operators provide a bond, letter of credit, or cash deposit as financial security with the filing or renewal of their organization reports. By 2005, all operators were transitioned to 'universal bonding' and the Legislature authorized RRC to accept well-specific plugging insurance policies as an alternative form of financial assurance. In 2005, an Orphan Well Reduction Program was created to plug "orphaned" wells. Orphaned wells are those that were inactive for more than 1 year and slated for permanent capping. The RRC then seeks reimbursement for the cleanup and plugging expenditures from the responsible parties through the Office of the Attorney General.

The OFCU Fund is supported entirely by fees, penalties, and other payments collected from the oil and gas industry. Drilling permit fees, which were the principal source of revenue for the Well Plugging Fund, were transferred into the new OFCU Fund. In place of the flat $100 fee for a drilling permit, an applicant now pays a fee ranging from $100 to $200 depending on the depth of the well. Another major source of revenue for the fund is a regulatory fee on the production of oil and gas: 5/16 of a cent per barrel of oil and 1/30 of a cent per thousand cubic feet of gas. These fees are collected by the Comptroller and deposited into the Fund. Following are some other additional sources for this OFCU Fund:

- Fees submitted as alternative to a bond or letter of credit
- Proceeds from forfeited bonds or letters of credit
- Pipeline severance fees
- National Pollutant Discharge Elimination System permit application fees
- Hazardous oil and gas waste generation fees
- Oil and gas waste hauler permit application fees
- Well plugging and remediation reimbursements
- Certain administrative and civil penalties
- Private contributions
- Interest.

The RRC currently has an inventory of approximately 700 wells that have been approved for plugging from the OFCU Fund.

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STATE REPORT—WYOMING

1. Background and History

Resource extraction is, and has been historically, Wyoming's largest industry. Only one of Wyoming's 23 counties does not produce coal, oil, natural gas, or a combination of those resources (USEIA 2014).

Wyoming ranks among the top ten states in the U.S. for crude oil, natural gas, and coal production. It is currently ranked fifth overall for natural gas and first in coal production. Wyoming typically accounts for 2 to 3 percent of U.S. crude oil production annually. As one of the top natural gas-producing states in the nation, Wyoming typically accounts for just under one tenth of U.S. production. Natural gas is produced throughout the state, although a majority of Wyoming's natural gas is produced from gas fields in and around the Greater Green River Basin in the southwest part of the state. Recovery of coalbed methane from coal seams in the Powder River Basin (PRB) has grown rapidly since the late 1990s and accounts for about one fifth of state's natural gas production. Recent low natural gas prices have slowed coalbed methane development and, in some cases, made well production and development uneconomic. Wyoming leads the nation in coal production, accounting for two fifths of all coal mined in the U.S. The eight largest coal mines in the U.S. are all in Wyoming's PRB. Wyoming supplies more energy to the nation and has more producing federal oil and gas leases than any other state (USEIA 2014).

2. Regulatory Structure

There are three regulatory agencies that oversee oil and gas and mining bonding requirements in the State of Wyoming. All three agencies require bonds or other approved financial guarantees from operators for resource extraction activities.

- The Office of State Lands and Investments (OSLI) regulates all state lands including bonding for well production. The OSLI includes the Mineral Leasing and Royalty Compliance Division. This division is responsible for the leasing of all subsurface minerals on State lands. Part of the authority of this division is to review, approve, and record a significant number of lease assignments, company name changes, bonds, letters of credit, powers of attorney, oil and gas units, pooling arrangements, and communitization agreements.
- The Wyoming Oil and Gas Conservation Commission (WOGCC) was established in 1951 and has general oversight powers over all oil and gas production on state and private lands. The WOGCC regulates industry practices and procedures with regard to construction, location, and operation of wells and production pits (Wyoming State Review 1991). This authority includes the specific responsibility to monitor and regulate operations and enforce regulations associated with oil and gas production including oversight of bonding and financial commitments required of operators.

- The Wyoming Department of Environmental Quality (DEQ) administers general environmental protection regulations. The DEQ is responsible for enforcing state and federal environmental laws with a focus on regulating resource development activities. The DEQ's Land Quality Division (LQD) administers and enforces all statutes and regulations related to mining and reclamation within the State of Wyoming. The LQD has the authority to require permitting and licensing of all operator actions at surface and underground mine facilities. Each mining operation must be covered by a reclamation bond in the event that the operator is unable to fulfill the reclamation requirements. The LQD's authority is derived from the Federal Surface Mining Reclamation and Control Act and the Wyoming Environmental Quality Act.

These agencies and their bonding requirements are discussed in the sections below.

2.1 Office of State Lands and Investments

The Board of Land Commissioners (BLC) is authorized to lease state lands for oil and gas production. "State Lands" are defined as all lands under jurisdiction of the BLC in which the Board owns some or all of the mineral estate (Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas Section 2[f]):

> "The board of land commissioners may lease any state or state school lands for oil and gas for a primary term up to ten (10) years and as long thereafter as oil or gas may be produced in paying quantities, and may extend the term of existing oil and gas leases in good standing for as long as oil or gas may be produced in paying quantities." (W.S. 36-5-101 (a)).

The BLC is also authorized to require of operators both performance bonds and lease bonds. Per Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 8, Lease Term, the BLC requires operators to post a performance bond when a lease extension is granted. The lease extension performance bond is intended to ensure that the operator drills a well in a timely manner. Per Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13, Bonds, the Director of the BLC requires operators to post a lease bond prior to the start of operations. The lease bonds are designed to ensure compliance with lease terms. In addition, the BLC requires an additional bond for idle wells. These three bonds are discussed separately below.

2.1.1 Lease Extension Performance Bond

When extending the term of an existing undeveloped lease, lessees are required by the BLC to post a $10,000 cash bond in the form of a certified or cashier's check made payable to the Office or a $10,000 certificate of deposit in the name of the OSLI. This bond is required to secure the payment of liquidated damages if the well is not started or completed, or if the well is lost, during the lease extension period.

2.1.2 Lease Bond

Before commencing activities on a lease, an operator must submit necessary applications to the WOGCC, and the Director of the OSLI must approve an adequate lease bond.[11] (Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas Section 13(a))

2.1.2.1 Purpose of the Lease Bond

The lease bond binds the principal and its surety for:

(i) The payment of all moneys, rents, and royalties accruing to the BLC
(ii) Full compliance with all applicable statutes and terms and conditions of the BLC's leases and rules and regulations
(iii) The proper plugging and abandonment of all inactive, non-producible wells on the leases
(iv) Reclamation of the surface
(v) For the payment of all disturbance to the surface and improvements thereon (Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13(b)).

2.1.2.2 Lease Bond Amounts

There is no single lease bond amount set in regulation. The bond amount "shall be in an amount found by the Director [of OSLI] sufficient to protect and indemnify the State of Wyoming." (Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13(b))

In lieu of individual lease bonds, the lessee may request and the Director may allow the lessee to file a corporate surety bond in the sum of not less than $100,000 covering all of the lessee's state leases (Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13(d)). This suggests a ceiling of $10,000 per individual lease bond.

2.1.2.3 Acceptable Lease Bond Financial Mechanisms

Per Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13(c), a lease bond shall be one of the following:

(i) A corporate surety bond executed by the lessee and by a surety authorized to do business in the state

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[11] Note that the Director of OSLI may require a per-well bond instead of allowing bonding per lease. (Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13(e))

(ii) A cash bond
(iii) A certified cashier's check made payable to the OSLI
(iv) A certificate of deposit in the name of the OSLI
(v) Non-revocable letters of credit
(vi) AAA-rated debentures of sufficient market value to meet bonding minimums with a signed stock power made out to the OSLI.

2.1.2.4 Modifications of Bonding Amounts

Wyoming regulations provide the Director of OSLI several avenues through which bonding amounts may be changed over time. Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 10(b) notes that the Director can disapprove the proposed assignment or transfer of a lease or an interest in a lease if the Director determines that "existing bonding is insufficient to cover lease premises activities." In addition, Wyoming Rules and Regulations Chapter 18, Leasing of Oil and Gas, Section 13(e) notes that OSLI "may at any time reduce or increase the amount of the bond as conditions may require" when OSLI is notified of changes in operations on a lease.

2.1.3 Idle Well Bonds

WOGCC rules require that operators either properly plug and abandon all wells made dormant within 180 days after first reaching that status, or post an additional bond with OSLI in the amount of $10 per foot of well depth. This per-foot bonding rate was increased in 2014 from the previous rate of $2 per foot of well depth.[12] Wyoming regulations do not specify the form of the bond, but any of the financial mechanisms suitable for lease bonds are assumed to be suitable for idle well bonds.

2.1.4 Mining Bonds

Regulations governing the leasing and oversight of state lands for coal mining are contained in Chapter 19 of the Wyoming Rules and Regulations. The language related to the bonding of these activities (including bonding amounts and acceptable types of financial mechanisms) is functionally identical to the language related to the bonding of oil and gas operations as presented in the sections above.

2.2 Wyoming Oil and Gas Conservation Commission

Wyoming statutes and regulations authorize the WOGCC to require bonds for active wells, idle wells, and for surface access in split estate cases. The bonds are discussed in the sections below.

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[12] A 2009 study conducted by researchers at the University of Wyoming "identified that reclamation costs are strongly correlated to well depths." (Anderson and Coupal 2009) The study identified a typical reclamation cost of approximately $10.00 per foot of well depth; this was the driver behind the change in the per-foot bonding rate in 2014.

2.2.1 Active Wells

Wyoming statute states that the WOGCC can require “the furnishing of a surety bond or other guaranty, conditioned for or securing the performance of the duty to plug each dry or abandoned well or the repair of wells causing waste and compliance with the rules and orders of the commission.” (W.S. 30-5-104 (d)(i)(D)) The WOGCC requires that an owner or operator file with the WOGCC a “good and sufficient bond…conditioned that … upon permanent abandonment each well shall be plugged in accordance with the Rules and Regulations of the Commission.” (Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules, Section 4 (a))[13]

Table 2.2-1 presents the current bonding amounts for active wells. Blanket bond amounts were increased in July 2000 from $25,000 to $75,000.

Table 2.2-1 Current Bonding Amounts for Wells

Infrastructure Description	Current Bonding Amount
Single well less than 2,000 feet deep	$10,000
Single well more than 2,000 feet deep	$20,000
Blanket bond covering all wells, including wells less than 2,000 feet deep	$75,000

Notes:
Blanket bond amounts have not been adjusted since July 1, 2000. If an operator had in place a blanket bond in the amount of $25,000 (the previous bonding amount) prior to July 1, 2000, that bond was grandfathered and the operator was not required to increase their bond amount to the $75,000 level. (Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules, Section 4 (a)(iii))
Sources: Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules, Section 4 (a).

2.2.2 Idle Wells

The WOGCC requires an operator to post a bond for each well that is idled. This bond is in addition to the active well bond discussed above.[14] If an operator has a grandfathered $25,000 blanket bond, the WOGCC will require the operator to post a bond in the amount of $10 for each foot of idled well depth once the total depth of idled wells exceeds 2,500 feet. If an operator has a $75,000 blanket bond, the WOGCC will require the operator to post a bond in the amount of $10 for each foot of idled well depth once the total depth of idled wells exceeds 7,500 feet. As wells are removed from “idle” status, the bonding amount is reduced accordingly.

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13 Note that, where a bond in satisfactory form has been filed by the Owner/Operator in accordance with other state, federal, or Tribal lease requirements, WOGCC can waive the required active well bond.

14 "Idle well" means any well that is not producing, monitoring, or disposing (Wyoming Rules and Regulations Chapter 3, Operational Rules, Section 4 (c)).

The idle well bond amount is increased every 3 years by the percentage change in the Wyoming consumer price index. When additional well bonding is required, the WOGCC may allow the operator to post at least 5.55 percent of the new bond amount each month for 18 months or until the amount of the bond has been posted. WOGCC may also require the operator to post the entire amount within a shorter timeframe.

Bond amounts may be adjusted at the request of the operator. Adjustments are based on specific well conditions and circumstances. In lieu of additional bonding, the Supervisor may accept a detailed plan of operation which includes a time schedule to permanently plug and abandon idle wells or take actions necessary to remove the well from idle status (Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules, Section 4(e).

When ownership of a well is transferred, the Supervisor must be notified. Notification allows the Supervisor to evaluate if the wells being transferred require additional bonding. If additional bonding is deemed necessary, the previous owner remains liable for plugging of the wells until the new owner provides the additional requested bonding amount (Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules, Section 4(f)).

2.2.3 Release of Bonds

The active well or idle well bond or bonds required by the WOGCC will remain in place for wells until:

- (i) The permanent plugging and abandonment of the well or wells has been approved by the Supervisor.
- (ii) The well has been properly converted to a water well in a manner approved by the Supervisor, in conjunction with the State Engineer.
- (iii) The successive Owner/Operator or purchaser of the well or wells/ or sites has provided a bond or other acceptable surety.
- (iv) The bond has been released by the WOGCC (Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules, Section 4 (b)).

2.2.4 Acceptable Bond Types

The WOGCC accepts surety bonds as a financial guarantee. In place of a surety bond, an operator may use a cashier's check, certificate of deposit (CD), or a letter of credit that meet the requirements outlined in Sections 5 and 6 of the Wyoming Rules and Regulations Chapter 3, Operational Rules, Drilling Rules.

2.2.5 Surface Access Bond

Wyoming Statute § 30-5-402, entry upon land for oil and gas operations and nonsurface disturbing activities; notice; process; surety bond or other guaranty; negotiations states the following:

"(c) Entry upon the land for oil and gas operations shall be conditioned on the oil and gas operator providing the required notice, attempting good faith negotiations and:

(i) Securing the written consent or waiver of the surface owner for entry onto the land for oil and gas operations;

(ii) Obtaining an executed surface use agreement providing for compensation to the surface owner for damages to the land and improvements as provided in W.S. 30-5-405(a);

(iii) Securing a waiver as provided in W.S. 30-5-408; or

(iv) In lieu of complying with paragraph (i) or (ii) of this subsection, executing a good and sufficient surety bond or other guaranty to the commission for the use and benefit of the surface owner to secure payment of damages. The amount of the initial bond or other guaranty shall be determined pursuant to W.S. 30-5-404(b)."

The bond shall be in an amount of not less than $ 10,000 per well site on the land (W.S. 30-5-404). The following are acceptable financial mechanisms to ensure the bond: a surety bond, a first-priority security interest in a deposit of the proceeds of a collected cashier's check, a first-priority security interest in a certificate of deposit or an irrevocable letter of credit. Regardless of financial mechanism used, the bond shall be in an amount and including other terms, conditions, and requirements determined by the WOGCC.

2.3 Bonding, Department of Environmental Quality, Land Quality Division

The DEQ's LQD permits and licenses all operator actions at surface and underground mine facilities. Each mining operation must be covered by a reclamation bond in the event that the operator is unable to fulfill the reclamation requirements. This bonding is discussed below.

2.3.1 General Bonding Requirements

For an initial mining bond, the bond amount must be equal to the estimated cost of reclaiming the affected land disturbed and restoring any groundwater disturbed by in situ mining during the first year of operation under each permit. The estimated cost shall be based on the operator's cost estimate submitted with the permit plus the Administrator's estimate of the additional cost to the state of bringing in personnel and equipment should the operator fail or the site be abandoned. In no event shall the bond be less than $10,000, except for limited mining operations authorized and bonded under W.S. 35-11-401(e) or any non-coal mine, the affected land of which, excluding roads, is 10 acres or less, in which case the bond amount shall be set by the Administrator with approval of the Director to cover the cost of reclamation, and in no event less than $200 per acre, for affected land.

For renewal bonds, the bond amount must be equal to the estimated cost of reclaiming the land to be disturbed during that renewal period, and the estimated cost of completing reclamation of unreleased lands and groundwater disturbed during prior periods of time. The estimated cost shall be based on the operator's cost estimate, which shall include any changes in the actual or estimated cost of reclamation of unreleased affected lands, plus the Administrator's estimate of the additional cost to the state of bringing in personnel and equipment should the operator fail or the site be abandoned. In no event shall the bond be less than $10,000, except for limited mining operations authorized and bonded under W.S. 35-11-401(e) or any non-coal mine, the affected land of which, excluding roads, is 10 acres or less, in which case the bond amount shall be set by the Administrator with approval of the Director to cover the cost of reclamation, and in no event less than $200 per acre, for affected land (W.S. 35-11-417).

Exploratory drilling programs also require bonding. Bonding amounts for exploratory coal drilling are established per exploration area in the amount of $10,000. This initial amount can be reduced if the operator can provide a lower reclamation cost estimate following established calculation principles. Non-coal exploratory drilling bond amounts are based on the cost of drill hole abandonment and surface reclamation in accordance with established engineering principles (Wyoming Rules and Regulations, Chapter 8 Section 4 (a)).

Limited mining operations (defined as those affecting 15 acres or less of land, excluding access roads) require bonds in the amount of $2,000 per acre, except for quarries, for which the bond amount shall not exceed $3,000 per acre of affected land. Reclamation of access roads must be included when calculating the total bond amount, although access roads are not included in the total area when determining if an operation is a “limited mining operation.” The DEQ can increase the per-acre bonding amount if it is determined necessary to ensure reclamation.

2.3.2 Calculation of Bonding Amounts

W.S. 35-11-411(d) authorizes the DEQ Director to establish the bond amount based on information submitted in an annual operating plan and inspection and other materials developed by the operator. The Wyoming Mining Association (WMA) Reclamation Subcommittee and the LQD cooperatively developed a standardized methodology for determining reclamation costs and bonding amounts (Guideline No. 12 – Standardized Reclamation Performance Bond Format and Cost Calculation Methods). Operators are not required to use the methodology.

For surface coal mining operations, the bond is calculated by taking into account both annual (Area) and total (Incremental) reclamation liabilities. The Area bond amount is the estimated cost of completing the maximum amount or rough backfilling during the annual bonding period. The Incremental bond amount is the estimated cost of performing all reclamation requirements other than that work covered under an Area bond. The total estimated cost is based on the operators cost estimate (Area plus Incremental Bond) plus the Administrator's estimate, which includes additional cost to the State to reclaim the land should the site be abandoned by the operator.

2.3.3 Release of Bonds

The retained bond may be released once the reclamation program has been completed and approved by the Administrator. Upon receipt of the notification and request and within 60 days, the Administrator will inspect and evaluate the reclamation work and report his findings to the Director. If the Director finds that the reclamation meets the necessary requirements, he can notify the operator and order the State Treasurer to release that portion of the final bond. The DEQ may retain a portion of the bond for at least 5 years as provided in W.S. 35-11-417(e), or for so long thereafter as necessary to assure proper revegetation of the reclaimed areas, as provided for in the operator's reclamation plan. Earlier release of the bond is possible with a signed release from the surface owner and approval by the Administrator and Director.

The bond for revegetation shall be retained for not less than 10 years after the operator has completed seeding, fertilizing, irrigation, or other work to ensure revegetation (Wyoming Rules and Regulations, Chapter 4, Section 2 (d)(i)(G)).

2.3.4 Acceptable Bond Types

In lieu of a surety bond, the operator or its principal may deposit federally insured certificates of deposit payable to the DEQ, cash or government securities, irrevocable letters of credit issued by a bank organized to do business in the United States, or a combination of all four.

2.3.4.1 Self-Bonding Program

Operators may also avail themselves of DEQ's Self-Bonding Program[15]. To qualify for self-bonding, the operator must meet one of the following criteria summarized from Wyoming Rules and Regulations Chapter 11, Section 2 (vii):

- The operator has a rating for all bond issuance actions over the past 5 years of "A" or higher by a nationally recognized rating organization.
- The operator has a tangible net worth of at least $10 million, and a ratio of total liabilities to net worth of 2.5 times or less, and a ratio of current assets to current liabilities of 1.2 times or greater.

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15 "Self-bond" means an indemnity agreement in a sum certain made payable to the state, with or without separate surety. The indemnity agreement is signed by the permittee and, if applicable, the parent or non-parent corporate guarantor (Wyoming Rules and Regulations Chapter 11, Self-Bonding Program, Section 1 (a)).

- The operator's fixed assets in the United States total at least $20 million, and the operator has a ratio of total liabilities to net worth of 2.5 times or less, and a ratio of current assets to current liabilities of 1.2 times or greater.

Imagine the result

State of Alaska,
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Decommissioning, Removal, and Restoration Regulatory Review

International Report—Brazil, Russia, United Kingdom, Work Bank, and Canada [Federal Jurisdictional Areas, Alberta, British Columbia, Manitoba, Newfoundland and Labrador, Nova Scotia, Nunavut, Ontario, Quebec, Saskatchewan, Yukon]

November 2014

ARCADIS

Conrad P. Mulligan
Senior Scientist

International Report—Brazil, Russia, United Kingdom, Work Bank, and Canada [Federal Jurisdictional Areas, Alberta, British Columbia, Manitoba, Newfoundland and Labrador, Nova Scotia, Nunavut, Ontario, Quebec, Saskatchewan, Yukon]

State of Alaska
Decommissioning, Removal, and Restoration Regulatory Review

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Acronyms and Abbreviations

International Report–Brazil

ANP	National Petroleum Agency (Agência Nacional de Petróleo, Gás Natural e Biocombustíveis)
CNPE	National Energy Policy Council (Conselho Nacional de Política Energética)
CONAMA	National Council for the Environment (Conselho Nacional de Meio Ambiente)
DNPM	National Department of Mineral Production
FPSO	floating production storage and offloading structure
IBAMA	Brazilian Institute of the Environment and Renewable Natural Resources (Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais)
MME	Ministry of Mines and Energy (Ministério de Minas e Energia)
OEFA	Authority of Environmental Supervision
OPEC	Organization of the Petroleum Exporting Countries

International Report–Norway

Act	The Petroleum Act of 29 November 1996 No. 72
Regulation	Petroleum Regulation of 17 June 1997 No. 653
OSPAR Convention	Oslo Paris Convention for the protection of the marine environment of the NorthEast Atlantic
The Ministry	Royal Ministry of Petroleum and Energy

International Report–Russia

EA	Environmental Assessment
MNRE	Ministry of Natural Resources and Ecology
SEER	State Environmental Expert Review

International Report–United Kingdom

CS	continental shelf
DECC	Department of Energy and Climate Change

DRD	Decommissioning Relief Deed
DSA	Decommissioning Security Agreement
EU	European Union
HM	Her Majesty's
JOA	Joint Operating Agreement
LoC	Letter of Credit
OECD	Organization for Economic Co-operation and Development
UK	United Kingdom of Great Britain and Northern Ireland
UKCS	United Kingdom Continental Shelf

International Report–World Bank

AIG	American International Group
IBRD	International Bank for Reconstruction and Development
ICSID	International Centre for the Settlement of Investment Disputes
IFC	International Finance Corporation
MIGA	Multilateral Guarantee Agency
PGI	Petroleum & Governance Initiative

International Report–Canada

Canada Federal Jurisdictional Areas

AANDC	Aboriginal and Northern Development Canada
A&D	Abandonment and Decommissioning
CNSC	Canadian Nuclear Safety Commission
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
C-NSOPB	Canada-Nova Scotia Offshore Petroleum Board
COGOA	Canada Oil and Gas Operators Act
FRR	Financial Responsibility Requirement
NEB	National Energy Board

NRCan	Natural Resource Canada
NSCA	Nuclear Safety and Control Act

Canadian Provincial Report—Alberta

AER	Alberta Energy Regulator
AESD	Alberta Environment and Sustainable Resource Development
CCA	Coal Conservation Act
CDN	Dollars Canadian
CRR	Conservation and Reclamation Regulation
DR&R	Dismantlement, Reclamation, and Remediation
EPEA	Environmental Protection and Enhancement Act
ERCB	Energy Resources Conservation Board
LFP	Large Facility Liability Management Program
LLR	Licensee Liability Rating
MFSP	Mine Financial Security Program
MMA	Mines and Mineral Act
OGCA	Oil and Gas Conservation Act
OSCA	Oil Sands Conservation Act
OWL	Oilfield Waste Facility Liability Program

Canadian Provincial Report—British Columbia

CDN	Canadian dollars
DR&R	Dismantlement, reclamation, and remediation
EPD	Environmental Protection Division
ISLOC	Irrevocable Standby Letter of Credit
LMR	Liability Management Rating
MMD	Mines and Minerals Division
OGAA	Oil and Gas Activities Act

OGC	Oil and Gas Commission
SSLA	Site-Specific Liability Assessment

Canadian Provincial Report—Manitoba

AFRA	Abandonment Fund Reserve Account
CCSM	Continuing Consolidation of the Statutes of Manitoba
CDN	Canadian Dollars
DMR	Division of Mineral Resources (Manitoba)
DR&R	Dismantlement, Restoration, and Remediation
MMA	The Mines and Minerals Act (Manitoba)
OGA	The Oil and Gas Act (Manitoba)
S&P	Standard and Poor's, Inc.

Canadian Provincial Report—Newfoundland and Labrador

CDN	Canadian Dollars
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board

Canadian Provincial Report—Nova Scotia

CDN	Canadian dollars
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
DR&R	Dismantlement, Reclamation, and Remediation
OAA	Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act
SOEP	Sable Offshore Energy Project

Canadian Provincial Report—Nunavut

AANDC	Aboriginal Affairs and Northern Development Canada
ARP	Abandonment and Reclamation Plan
CLARCs	Community Lands and Resources Committees
COGOA	Canada Oil and Gas Operations Act

CPRA	Canada Petroleum Resources Act
DIO	Designated Inuit Organization
GNWT	Government of the Northwest Territories
IOL	Inuit Owned Lands
MPRD	Mineral and Petroleum Resources Division
NPRD	Northern Petroleum Resources Directorate
NTI	Nunavut Tunngavik Incorporated
NRO	Nunavut Regional Office (AANDC)

Canadian Provincial Report—Ontario

CDN	Canadian Dollars
DR&R	Decommissioning, Removal, and Restoration
MNDM	Ministry of Northern Development and Mines
MNR	Ministry of Natural Resources
MOECC	Ministry of Environment and Climate Change

Canadian Provincial Report—Quebec

CDN	Canadian Dollars

Canadian Provincial Report—Saskatchewan

AOR	Acknowledgement of Reclamation Program
CDN	Canadian Dollars
DRP	Decommissioning and Reclamation Plan
DR&R	Decommissioning, Reclamation, and Remediation
EMPA 2002	Environmental Management and Protection Act, 2002
LLR	Licensee Liability Rating Program
MIEPR	Mineral Industry Environmental Protection Regulations

Canadian Provincial Report—Yukon

CDN	Canadian dollars
DR&R	Dismantlement, Reclamation, and Remediation
OGRB	Oil and Gas Resources Branch
OIC	Order in Council

INTERNATIONAL REPORT—BRAZIL

1. Background and History

Brazil has become a recognizable oil producer with significant new discoveries of oil plays off shore. The economic importance of these oil discoveries has been widely recognized in projections of future global energy markets. Brazil is projected to move into the top tier of the world's non-OPEC oil producers. As a result, there has been a coincident consideration of the importance of environmental protection and regulation in Brazil. The enactment of a National Environmental Policy in 1981 (Law No. 6.938 of 1981) in Brazil resulted in systemization of government bodies and their respective institutional powers and duties, such as the federal environmental agency Brazilian Institute of the Environment and Renewable Natural Resources (Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais [IBAMA], in charge of law enforcement and permitting); the National Council for the Environment (Conselho Nacional de Meio Ambiente [CONAMA], in charge of creation of regulatory standards); and several state environmental agencies. The National Environmental Policy has also defined the main instruments of environmental policy, such as environmental standards, zoning, licensing, environmental impact assessments, and penalties for non-compliance with environmental provisions. The environmental regulatory agencies created by the National Environmental Policy are:

- National Energy Policy Council (Conselho Nacional de Política Energética [CNPE])
- Ministry of Mines and Energy (Ministério de Minas e Energia [MME])
- National Petroleum Agency (Agência Nacional de Petróleo, Gás Natural e Biocombustíveis [ANP])
- IBAMA
- CONAMA

Brazil is an active participant in international conferences concerning the need to create an international offshore decommissioning fund and country regulatory process.

2. Regulatory Structure

The Brazilian legislative framework for environmental protection is comprised of federal, state, and local environmental laws and regulations. One of the most important Brazilian environmental laws is federal Law No. 6.938 of August 31, 1981, as amended, which created the Brazilian Federal Environmental Policy and established its purposes, formulation, and enforcement mechanisms. The formulation and enforcement mechanisms imposes, among other things:

- Environmental licensing requirements for the construction, installation, expansion, and operation of plants and activities that use environmental resources and that could actually or potentially cause pollution or any sort of environmental damage
- The obligation to repair damage caused to the environment and third parties or compensate those affected, regardless of actual fault (strict liability).

Federal Law No. 9.605 of February 12, 1998 imposes criminal and administrative sanctions on individuals and companies whose conduct and activities harm the environment. In Brazil, individuals or companies that commit criminal offenses against the environment can be punished with sanctions ranging from fines to imprisonment (individuals) or dissolution (companies). Administrative sanctions imposed by the government's environmental protection agencies on those who violate environmental laws and regulations include, among other things:

- Fines
- Partial or total suspension of activities
- Forfeiture or restriction of tax incentives or benefits
- Forfeiture or suspension of credit lines made available by official credit establishments.

Activities and undertakings that are deemed to effectively or potentially cause pollution are subject to environmental licensing requirements (Law No. 6.938 of August 31, 1981). The licensing procedure involves three licenses:

- Preliminary License (Licença Preliminar), which confirms that the concept of the undertaking is environmentally viable and approves its location.
- Installation License (Licença de Instalação), which authorizes construction of the undertaking.
- Operating License (Licença de Operação), which authorizes the operation of the undertaking.

The environmental licensing process is normally conducted at the state level (by the relevant state environmental agency), but is sometimes conducted at the federal level by the IBAMA if the project has interstate impacts. Environmental licenses are normally only required for the development and exploitation phases, but in certain states environmental licenses are also required for exploration work.

Environmental licenses are valid for a set period and the relevant company must request renewal of the license at least 120 days before its expiration date, to allow continuous operation before the issuance of the new license.

Companies undertaking projects with significant environmental impacts must pay an environmental compensation fee of a maximum of 0.5 percent of the total implementation costs of the undertaking.

3. Requirements for Submitting, Updating, and Having Mining Operations and Oil Well Closure Plans Approved

3.1 Mining

The requirements for a mine closure plan vary within each jurisdiction in Brazil. This is due to a range of factors, including whether it is handled at a national, provincial/state level, or a combination of these two. Although mine closure and oil well abandonment is principally regulated at the national level through its constitution, the Brazilian Mining Code, and the Brazilian Petroleum Law, closure is also supplemented by regulations at the state level concerning local taxes, environmental matters, and soil usage. Additionally, variations exist between mining operations and oil and gas. Mining in Brazil is regulated by Decree-Law 227, 1967 ("the Mining Code") along with the rulings of the National Department of Mineral Production. To obtain an environmental installation license in Brazil, a mine closure plan must be submitted as part of a series of studies. Specifically, the plan must cover the minimizing of environmental degradation and negative impacts on the environment. The Brazilian National Department of Mineral Production (DNPM) evaluates the plan and issues a subsequent report. This report must form part of the application to the MME to close a mine. The application must contain:

- A report on the work performed to date
- Characterization of the remaining resources
- A topographic and landscape report considering the stability, erosion control, and drainage aspects
- A work and financial chronogram of the proposed decommissioning activities.

Approval is only granted if the decommissioning plan clearly evidences compliance with the environmental conditions and the possibility of the area being used for future economic activities. The closure plan may not be taken into action without the DNPM's prior approval. The closure plan must be updated periodically, although the timing requirement for each update is not expressly dictated. The closure plan has to contain all items mentioned in Section 20.4.1 of Annex I from Ordinance No. 237/2001.

3.2 Oil and Gas

For oil well abandonment in Brazil during the exploration and development phases, oil companies must notify the Brazilian ANP, and, during the production phase, oil companies can abandon oil wells only after ANP's formal authorization. Oil wells cannot be abandoned if the necessary operations for such actions may impact neighboring oil wells, unless the well to be abandoned represents a safety or environmental threat to the environment. There is no requirement for an abandonment plan because ANP Ordinance No. 25/2002 already sets out in detail the procedure to be followed by oil companies to carry out well abandonment. Nevertheless, ANP Resolution No. 13/2011 provides for a report for the handover of the concession areas, which may be submitted for only part of the concession area or the entire concession area and must encompass all abandoned wells. The content of the report is detailed in ANP Resolution No. 13/2011. In cases where there is non-compliance with mine closure and oil well abandonment, sanctions can be applied ranging from a fine to the termination of the license or concession agreements. Generally, across the region, some form of closure or abandonment plan must be submitted to the government at the start of the project. Most jurisdictions require that this plan be updated over the course of the project. In Argentina, Chile, and Peru, there are proscribed times for updating the plan; however, in Colombia, the plan must be updated only when there are variations in the mining operation and, in relation to oil and gas, there are no specific time frames. Peru also provides an interesting case study on this point. In the case of abandoning oil wells, license holders can submit a plan for temporary cessation, partial abandonment, or total abandonment. Each of the plans mentioned must comply with the following requirements: (i) include actions for remediation, reforestation, decontamination and removal of facilities, and other necessary measures to abandon the area, in compliance with the corresponding timetable, described in the Environmental Impact Assessment, (ii) the compliance of the Plan will be supervised by the Authority of Environmental Supervision (OEFA).

4. Bonding and Financial Security Conditions

When an oil and gas company is dismantling an operation, the following is required;

When abandoning or decommissioning physical structures, especially wells, the concessionaire shall comply with the rules provided under ANP Ordinances No. 25, of March 6, 2002, and No. 27, of October 18, 2006, which set forth several technical requirements for preparation and completion of abandoned wells and also for decommissioning facilities and assets used during the production phase. xxxxAll assets, either movable or fixed, belonging to the concession area, the costs of which are deductible according to the rules established by the ANP from the special participation, and that, at ANP's discretion, are considered necessary to the continuity of the operations, or are able to be used for governmental purposes, may have their ownership reverted to ANP.

The decommissioning obligations and liabilities are set out in contractual provisions included in the concession agreement (clauses 13, 18, and 21), in addition to the technical requirements for abandonment procedures (ANP's Ordinance No. 25/2002) and surrender of acreage (ANP Resolution No. 13/2011).

When a concessionaire relinquishes or abandons blocks within a concession, clauses 13, 18, and 21 impose certain requirements, for example that the concessionaires:

- Pay all costs.
- Issue a guarantee regarding abandonment operations (*garantia de desativação e abandono*), which covers activities that constitute definitive well abandonment.

The concession agreement also provides that the concessionaire’s obligation to perform all of the operations necessary to inactivate and abandon a given field, at its own cost and risk, are not waived when the inactivation and abandonment guarantee is presented.

In addition, concessionaires must comply with applicable law (for example, environmental law) and international best practices. International best practices will be inferred as those provided by international regulation for offshore operations, such as the United Nations Convention for the Continental Shelf (Geneva 1958) and the United Nations Convention on the Law of the Sea 1982 (UNCLOS). Accordingly, the relinquishment set out in the concession agreement will not exempt concessionaires from fulfilling all outstanding obligations, or from any liabilities, irregularities, or infractions verified later.

When the block is excluded from the concession area or when the concession agreement is terminated, the assets required for operations to continue or that are deemed of public interest are reverted to the federal government, and to the administration of the ANP, provided that the concession area comprises only one block. The non-reverted assets will be removed and disposed of by the concessionaires, at their own cost and risk.

Decommissioning occurs both on shore and off shore. Onshore commissioning is typically regulated at a local level and traditionally is less complex. A common onshore decommissioning includes plugging and abandoning operations. The costs for decommissioning offshore rigs in Brazil are dependent on the location and type of facility (including the complexity), the number of structures to be removed, the depth of the water at the location of the rig, the depth of the wells, conductors, removal method, transportation, and final disposal for the structures. Prior to decommissioning an offshore operation, detailed planning must occur. The planning must include the cessation of oil and gas, safe plugging, removal of all or part of the installation, disposal or recycling of the removed part(s), and a plan for demobilizing the floating production storage and offloading structure (FPSO), which includes subsea equipment and pipelines. It is difficult to estimate the total cost to implement all of these activities in compliance with the regulatory regime in the area where offshore operations were occurring.

Phases of offshore decommissioning include:

1) Rendering redundant structures “clean,” and petroleum and chemical free; abandoning wells, removing conductors/risers, flushing and cleaning the process/utility systems, confirming that all vessels, piping, and other support equipment are gas and oil free as these components are prepared for lifting and removal.

2) Deconstructing and removing the installation and associated components.
3) Conducting site restoration followed by inspection of the site and appropriate monitoring of the site.

An additional and imperative component of the international offshore decommissioning process is the protection of the environment consistent with the UNCLOS.[1]There are regional conventions that aspire to regulate decommissioning of oil and gas installations and marine pollution, but none of the regional conventions in existence provide regulations for abandonment financing. However, there are laws and regulatory requirements in the United States and the United Kingdom that require financial assurance for the activity prior to approving an offshore decommissioning activity. It is similar to United States regulatory agencies requiring financial assurance for sites being regulated by Resource Conservation and Recovery Act (RCRA) corrective action.

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World Bank Organization.

[1] United Nations Convention on the Law of the Sea-Article 60.3, was entered into force on November 16, 1994.

INTERNATIONAL REPORT—NORWAY

1. Background and History

In May 1963, the Norwegian government proclaimed sovereignty over the Norwegian continental shelf. A new act stipulated that the State was the landowner, and that only the King (government) could grant licenses for exploration and production. Offshore production from the North Sea began with the Ekofisk field in June 1971, and several large discoveries were made during the following years. In the 1970s, exploration activity was concentrated in the North Sea, but exploration gradually shifted north to the continental shelf. This shift led to world-class discoveries, and production from the Norwegian continental shelf has since been dominated by large fields including Ekofisk, Statfjord, Oseberg, Gullfaks, and Troll. These fields have been, and still are, important components of the petroleum industry in Norway.

The Petroleum Act of 29 November 1996 No. 72 (Act) relating to petroleum activities, establishes the licensing system for petroleum activities in Norway. According to the Act and associated regulations of 17 June 1997 No. 653 (Regulation), licenses are awarded for exploration, production, and transport of petroleum. The Act confirms that the property rights to the petroleum deposits on the Norwegian continental shelf are owned by the State. Approval and permits are required for each phase of development through dismantlement, removal, and restoration. Before a production license is awarded for exploration or production, the relevant area must be opened for petroleum activities. An impact assessment must be carried out to evaluate the economic and social effects, and the environmental impact.

2. Regulatory Structure

In accordance with the Act, a licensee shall submit a decommissioning plan 2 to 5 years before the license expires or is relinquished, or before facility operation ceases. The decommissioning plan must be submitted to the Royal Ministry of Petroleum and Energy (the Ministry). Disposal may include further use of a platform in petroleum activities, other uses, complete or partial removal, or abandonment. Notification to the Ministry other than the decommissioning plan is necessary when the use of the facility is expected to terminate permanently before the expiration of the license.

The decommissioning plan has two main parts—a disposal section and an impact assessment. The first part discusses a disposal plan for shutdown of production and disposal of production facilities. The disposal proposal must contain the following items, as described by Section 44, Chapter 6, of the Petroleum Activities Act 29 November 1996 no 72:

i. The field history

ii. The facility, including location, depth, type of material, and other characteristics

iii. Deposit and production

iv. Relevant disposal alternatives

v. Other aspects relevant to the choice of disposal solution

vi. Recommended disposal solution, including a schedule for implementation of disposal

vii. Other information required pursuant to the safety regulations applicable at any time.

For relevant disposal alternatives identified and mentioned, the following items must be addressed in the proposal:

i. Technical, safety-related, environmental, and economic elements

ii. Relationship to other users of the sea, including information on and evaluation of impact on fisheries and shipping.

For facilities located on land or seabed subject to private property rights, the disposal portion shall focus only on disposal as it relates to alternative further use in petroleum activities.

The impact assessment portion must contain a description of the effect that each of the relevant disposal alternatives may have on commercial activities and the environment, what actions are necessary to reduce discharges and emissions in connection with disposal, and how to remedy any damage or inconvenience that may occur.

The impact assessment shall be prepared on the basis of an approved impact assessment program, which will be adapted to the extent of the disposal. The impact assessment shall be submitted to the Ministry concurrent with the disposal portion of the decommissioning plan at the latest. However, a draft of this portion would have been submitted before operation activities commenced, pursuant to Sections 22 and 45 of the Act. Among other items, the impact assessment should:

i. Describe the environment that may be significantly affected by the proposed disposal plan, and consider and make a balanced judgment with regard to the environmental impact including:

   a. Emissions to sea, air, and soil

   b. Possible material assets and monuments of cultural heritage that may be affected as a result of the development

   c. The consequences of the technical solutions chosen

   d. How environmental criteria and impact on the environment have been taken into account in the technical solutions that have been chosen

e. Possible and planned measures in order to prevent, reduce, and if possible, compensate for any significant adverse effects on the environment

ii. Consideration of how the facilities may be disposed of when petroleum activities have ceased

iii. Technical measures for emergency preparedness

iv. Environmental monitoring methods.

In summary, the impact assessment submitted with the decommissioning plan should give a short account of the relevant disposal alternatives, the envisaged effects of those disposal methods to the environment and other commercial activities, and documentation of activities.

Chapter 5 of the Act and Chapter 6 of the Regulation govern disposal of facilities or cessation of activities. In addition to the Act, the Oslo Paris Convention for the Protection of the Marine Environment of the NorthEast Atlantic (OSPAR Convention) also governs disposal of facilities. Under this Convention, only a small number of facilities can be abandoned on site. A disposal decision will be made on the basis of the impact assessment, the consultation opinions, the disposal section, and evaluations of the proposed disposal plan.

3. Bonding and Financial Security Conditions

The licensees at the time of the disposal decision are responsible for carrying out the disposal. In 2009, the Act was amended so that the party that sells part of a production license has an alternative liability for removal costs related to the sold share. When a decision is made regarding abandonment, the regulation stipulates that the licensees are liable for willful or negligent damage, harm, or inconvenience in relation to the abandoned facility. The licensees and the State can agree that future maintenance and responsibilities will be transferred to the State for an agreed upon financial compensation.

SOURCES CITED

The Petroleum Act of 29 November 1996 No. 72

Petroleum Regulation of 17 June 1997 No. 653

INTERNATIONAL REPORT—RUSSIA

1. Background and History

The mineral/oil and gas industry of Russia accounts for the production of mineral products, including metals both precious and industrial minerals, and oil and gas resources. In 2005, Russia ranked among the world's leading producers of mineral commodities including: aluminum, arsenic, bauxite, boron, cadmium, copper, diamond, iron ore, nickel, nitrogen, and vanadium in addition to oil and natural gas. In 2005, the Russian economy benefited significantly from high crude, gas, and ore prices. Oil revenues accounted for about 14 percent of the gross domestic product. As a result, over the past 20 years, Russia has enacted complex and strict environmental legislation that in many cases meets or exceeds commonly accepted international standards. The licensing regime is administered by the Ministry of Natural Resources and Ecology (MNRE) of the Russian Federation and the federal agencies under its jurisdiction. Subordinate to MNRE, the Federal Agency for Subsoil Use (Rosnedra) is the administrative agency primarily responsible for the regulation of oil and gas extraction. The Federal Service for Supervision of Nature Use (Rosprirodnadzor) oversees compliance with legislation regulating subsoil use and protection of the environment. Additionally, the Federal Environmental, Industrial and Nuclear Supervision Service (Rostekhnadzor) issues mining allotments that determine deposit boundaries, safety certificates, and operating licenses. Russia is continuing to develop its legislation and currently has new draft resolutions in the State Duma[2]. To date, the enforcement of existing regulations has been inconsistent.

Pursuant to the constitution of the Russian Federation, environmental protection falls within the joint competence of the Russian Federation and its constituent entities. Therefore, Russian environmental legislation is enacted at both federal and regional levels.

2. Regulatory Structure

In order to produce natural resources in Russia, a company must obtain a number of licenses and permits including a subsoil use license, a mining allotment, drilling permits, land use permits, operating licenses, and must acquire a positive concurrence on an environmental assessment.

2.1 Subsoil Use Law

The exploration and production of subsoil resources, including oil, natural gas, and mineral mining, is based on a licensing regime combining technical project and environmental approvals. The main bodies of legislation are contained in the Federal Law On Subsoil, dated February 21, 1992 (Subsoil Law), and the

[2] **The State Duma** (Russian: Госуда́рственная ду́ма (Gosudarstvennaya Duma, common abbreviation: Госду́ма (Gosduma) in the Russian Federation is the lower house of the Federal Assembly of Russia (legislature), the upper house being the Federation Council of Russia.

Regulation on the Licensing of Subsoil Use issued pursuant that law and Federal Law No. 7-FZ, On Environmental Protection, dated January 10, 2001 (Environmental Protection Law), and Federal Law No. 174-FZ, On Environmental Expert Review, dated November 23, 1995 (Environmental Expert Review Law). Rostekhnadzor issues mining allotments determining deposit boundaries, safety certificates, and operating licenses. These laws guide the subsoil work as well as the aboveground processing and infrastructure support activities. The subsoil permits and operating permits can be acquired separately based on the transition from exploration to production.

In addition, a large number of ministerial orders and governmental resolutions have been issued in implementing these regulations. The licensing regime for the Subsoil Law is administered by the MNRE and federal agencies under its jurisdiction. Rosnedra is the central administrative agency. It is headquartered in Moscow and has branches throughout the Russian Federation. Rosnedra is responsible for the issuance, suspension, and revocation of subsoil use licenses, the approval of deposit development plans, and the transfer and storage of geological information. Rosprirodnadzor oversees compliance with the legislation regulating subsoil use and protection of the.

Types of Subsoil Licenses - Subsoil legislation distinguishes the following types of subsoil use licenses with respect to the development of natural resources:

- Exploration Licenses – The maximum term for an exploration license is 5 years or 10 years if geological survey works are carried out on subsoil plots located within internal seawaters, territorial sea, and the continental shelf of the Russian Federation. Exploration licenses are awarded without a tender/auction upon the decision of a special commission formed by Rosnedra. Upon discovery of minerals, a production license is issued without a tender/auction to the holder of the exploration license. Production may not be undertaken under an exploration license.
- Production Licenses - Production licenses are issued with respect to deposits that have been explored, for which reserves have been registered in the state balance of reserves. The term length for a production license may be as long as is required for rational, full exploitation of the deposit (as documented in the feasibility study conducted for the project). Production licenses are awarded by tender or auction.
- Combined Licenses - Combined licenses are issued with respect to deposits that already have proven reserves required for production and that require substantial additional exploration of the deposit. The term of a combined license is split between the period required for the exploration and the period required for production. Combined licenses are awarded by tender or auction.

2.2 Environmental Protection Law

Pursuant to the constitution of the Russian Federation, environmental protection falls within the joint competence of the Russian Federation and its constituent entities; therefore, Russian environmental legislation is enacted at both federal and regional levels. The main federal laws regulating environmental protection are Federal Law No. 7-FZ, On Environmental Protection, dated January 10, 2001 (Environmental Protection Law), and Federal Law No. 174-FZ, On Environmental Expert Review, dated November 23, 1995 (Environmental Expert Review Law).

The Environmental Protection Law:

- Establishes the fundamental principles of Russian environmental regulation
- Provides an overall framework for environmental management
- Imposes general environmental protection requirements related to the construction and operation of various facilities that may be harmful to the environment.

Both the Environmental Expert Review Law and the Environmental Protection Law require the performance of an Environmental Assessment (EA) prior to the implementation of a project that may have an impact on natural resources. Both laws further provide that the construction and operation of various facilities are permitted only after the receipt of a positive concurrence from the unified State Environmental Expert Review (SEER) with respect to the relevant project documentation and proposed activity.

The EA evaluates the possible adverse environmental impact and ecological consequences and endeavors to develop measures for decreasing or preventing such adverse impacts. A positive SEER conclusion is an essential precondition for financing and implementing any project that may have an impact on the environment.

Russian environmental legislation at the regional level comprises various standards and procedures related to environmental permits and approvals that largely fall within the regulations established by the federal laws. In most cases, the regional legislation simply provides additional details with respect to the federal laws rather than setting forth entirely new region-specific regulations.

3. Financial Assurances

3.1 Subsoil Use Law

Transfer of Subsoil Use Rights - The subsoil license documents the rights of a particular entity to develop a particular subsoil deposit within a mining allotment limited by borders. The subsoil license itself and the rights evidenced by it may not be sold, assigned, or pledged. However, the law provides a procedure for the numerous instances in which such rights may be transferred, which results in the reissuance of the subsoil use license.

The transfer of subsoil use rights is possible under limited circumstances when the licensee:

- Changes its organizational form or legal status
- Merges with another legal entity
- Undergoes a division or spin-off
- Is deemed insolvent.

A licensee may also transfer its subsoil use rights to a newly created subsidiary established in order to carry out operations on a particular field, provided the following conditions are met:

- Incorporation in Russia: the new subsidiary must be a Russian company.
- Adequate facilities/assets: the property (physical assets) required to perform the operations.
- Operational permits: the new subsidiary must have available the permits (operational licenses) necessary to carry out the operations.
- Share in the charter capital: at the time of the transfer and reissuance of the subsoil license, the original licensee must own at least 50 percent in the charter capital of the new subsidiary.

The Subsoil Law permits the transfer of subsoil use rights within a group of companies:

- From a parent company to its subsidiary
- From a subsidiary to the parent company
- Between subsidiaries as directed by the parent company.

3.2 Obligations of the Licensee

The licensee generally undertakes certain commitments under the subsoil use license, the most important and capital-intensive of which are to:

- Achieve certain annual exploration and/or production targets
- Manage environmental contamination within specified limits and remedy instances of environmental pollution.

The licensee may also be obliged to fulfill certain social obligations in the area in which it operates, such as paying compensation to local indigenous groups and providing other types of support to the local communities. Failure to comply with the terms of the subsoil license (or with the provisions of the Subsoil Law or implementing regulations) can lead to penalties, suspension of production, and revocation of the subsoil license. The Rosprirodnadzor is the federal agency authority currently empowered to oversee compliance with the terms of the subsoil license.

3.2.1 Components of Subsoil Licenses

Subsoil licenses have a number of integral components, the most important of which is the licensing agreement. The licensing agreement must include:

- The commencement date and term of the license
- The boundaries of the field (which need to be additionally confirmed by a mining allotment before production can commence)
- The agreed upon level of production
- The title to recovered hydrocarbons and agreement as to geological information obtained in the course of operations
- Terms and conditions for compliance with standards of environmental protection and safety.

3.2.2 Offshore Operations

Operations in offshore areas beyond the 12-mile nautical territorial sea limit are separately governed by the Federal Law “On the Continental Shelf of the Russian Federation,” dated November 30, 1995, as amended (Continental Shelf Law), and the Federal Law “On the Exclusive Economic Zone of the Russian Federation,” dated December 17, 1998, as amended (Exclusive Economic Zone Law).

Offshore hydrocarbon operations on the continental shelf within a 200-nautical-mile zone fall under the jurisdiction of the agencies operating under the auspices of the MNRE, as well as several other governmental entities, including the Federal Security Service and the Federal Agency for Fisheries.

The exclusive economic zone of the Russian Federation is the marine area located from Russia’s 12-mile territorial sea up to 200 nautical miles from the coastal state baseline (or as provided by international law or treaty), including all islands located within the area.

The Exclusive Economic Zone Law sets up a framework for protective measures with regard to dumping, accidents at sea, and protection and conservation of icebound areas and specially designated areas.

Amendments to the Subsoil Law essentially limit the development of offshore fields to state-owned companies Rosneft, Gazprom, and their affiliates. Oil and gas deposits located on or extending into the continental shelf of the Russian Federation may be used only by Russian legal entities:

- That have no less than 5 years' experience developing continental shelf blocks in Russia
- In which the Russian Federation holds more than 50 percent of the total votes represented by the share capital of such entity, or otherwise control (directly or indirectly) more than 50 percent of the total number of votes.

Russian projects that have requirements for international funding and reporting will continue to require dual technical studies and engineering design approval through a State Expert Review and SEER. To achieve this, the international consultants and Russian Design Institutes will need to cooperate on a joint work program. Key issues to address in the joint work program will be to ensure that the most appropriate studies are carried out at the right stages, that capital expenditure is planned, that project economics are considered throughout the study, and that the environmental work program covers the additional studies necessary for the SEER.

3.3 Environmental Law

Permits for general use of natural resources (e.g., a subsoil license or water use agreement) carry limited transferability (i.e., they may be transferred to another entity only if the transferee meets certain criteria set by law and obtains the prior consent of an appropriate government authority). Permits for specific negative impact on the environment (e.g., hazardous waste management, operation of hazardous production facilities) are usually not transferable under Russian law.

3.3.1 Pay-to-Pollute

The Environmental Protection Law includes a pay-to-pollute provision that requires companies to obtain permits and pay the respective tariffs for such permits for adverse environmental impact caused by their activities, including:

- Emission of pollutants and other substances into the atmosphere
- Discharge of pollutants, other substances, and microorganisms into bodies of water, groundwater, and watersheds
- Pollution of subsoil and soil
- Disposal of industrial and consumption waste

- Environmental pollution caused by noise, heat, electromagnetic and ionizing radiation, and other types of pollution
- Other activities that may have an adverse environmental impact.

*** *In addition to making the pay-to-pollute payments (which are considered a fiscal levy, rather than a fine or sanction, on a company that produces negative impact on the environment), a company must also remediate any environmental damage caused by its activities (regardless of pay-to-pollute payments).*

4. Bonding and Financial Security Conditions

4.1 Subsoil Use Law

4.1.1 Termination of Subsoil Licenses

A subsoil license may be revoked for the following reasons:

1. Appearance of immediate danger to the health of the people working or living in the areas affected by operations related to subsoil use
2. Violation by the subsoil user of material terms of the license
3. Systematic violation by the subsoil user of the established rules for subsoil use
4. Occurrence of emergency situations (natural disasters, war, and others)
5. The subsoil user’s failure to commence operations in accordance with the established scope and term of the license
6. Liquidation of an enterprise or other subject of economic activities that holds the license for subsoil use
7. The subsoil user’s failure to file the reports required by Russian law
8. At the initiative of a subsoil user upon submission of the appropriate application.

In situations involving the first and fourth circumstances above, the subsoil use rights are terminated immediately if the authorities decide termination is necessary, provided a written notice has been served upon the subsoil user. In the second, third, and fifth instances described above, the subsoil use rights may be terminated after 3 months following written notice to the subsoil user regarding any violations, provided that the subsoil user has failed to remedy said violations within this 3-month period.

4.1.2 Obligations of the Licensee

The licensee generally undertakes certain commitments under the subsoil use license, the most important and capital-intensive of which are to:

- Meet certain annual exploration and/or production targets
- Keep environmental contamination within specified limits and remedy instances of environmental pollution.

The licensee may also be required to fulfill certain social obligations in the area in which it operates, such as paying compensation to local indigenous groups and providing other types of support to the local communities. Failure to comply with the terms of the subsoil license (or with the provisions of the Subsoil Law or impending regulations) can lead to penalties, suspension of production, and revocation of the subsoil license. The Rosprirodnadzor is the federal agency authority currently empowered to oversee compliance with the terms of the subsoil license.

Upon termination of the subsoil use rights, the subsoil user has to provide for liquidation and conservation of operations in the field at the operator’s cost.

A Closure Plan must be submitted to the Regional authorities 1 year before cessation of oil and gas production or mining production for approval by the appropriate entity.

4.2 Environmental Law

4.2.1 Environmental Liability

A violation of Russian environmental regulations may invoke civil, administrative, disciplinary, and/or criminal liability. Multiple categories of liability may be applied to a single violation. However, criminal liability cannot be imposed concurrently with administrative liability unless a violation can be attributed to different persons (e.g., when a company commits a violation as a result of its officer’s unlawful act or decision, the officer can be held criminally liable for the violation while the company can be held administratively liable for the same violation).

- Civil liability can be imposed upon a person/entity that actually caused the damage or, in the case of damage caused by so-called sources of increased danger (e.g., nuclear facilities, highly toxic substances), upon the owner of such facilities (regardless of whether his acts are attributable to the damage or not). Pursuant to Russian civil law, damages are divided into actual damages and lost profits. Compliance with environmental law (i.e., obtaining a SEER or making pay-to-pollute payments) does not release the company from its liability for damage caused to the environment.

Russian law provides for a 20-year statute of limitations for filing claims based on environmental liability, starting from the moment when the injured person learned or should have learned of the damage.

- Administrative liability can be imposed on individuals, officials, or companies by orders of the relevant state authorities, generally in the form of an administrative fine or an order of suspension or revocation of license. While administrative fines for non-compliance with the environmental legislation are often relatively insubstantial, orders of suspension or revocation of license often can have a significant impact on the company's operation and business.

The statute of limitations for the imposition of administrative liability is 1 year from the date when the offense was committed. If the offense is a continuing violation, the limitation period starts from the moment when the relevant state authority learned about the violation.

- Disciplinary liability can be imposed by an employer on employees who fail to perform their duties related to their environmental protection obligations (e.g., duties included in the company's internal regulations or an instruction related to the operation of a production facility). This type of liability is available only with respect to an intentional action or omission. The statute of limitations is usually 1 month from the date when the employer learned about the disciplinary offense.
- Criminal liability can be imposed upon individuals, including government officials and general directors and managers of companies, for material violations of law that may present a serious danger to the public. Criminal liability may be imposed only by courts if such liability is envisaged by a specific provision of the Criminal Code of the Russian Federation.

4.2.2 Pre-existing Environmental Liability

A person or company that acquires an asset (e.g., land or facilities) generally will not be liable for environmental violations that occurred prior to its ownership. Nevertheless, there is a risk of inheriting environmental liability if the environmental violation resulted in environmental damage and such damage continues to exist after the change in ownership of the asset. In such case, the environmental damage may be deemed a continuing violation, and the current owner may be held jointly and severally liable with the previous owner for past violations (particularly if it is not possible to allocate liability for damage). The current owner may then have the right to claim recourse against the previous owner, subject to any contractual arrangements they might have.

INTERNATIONAL REPORT—UNITED KINGDOM

1. Background and History

Natural gas in the United Kingdom (UK) has been produced from offshore fields in the North Sea since the late 1960s, and oil has been produced since the mid-1970s. The large majority of fields were discovered, developed, and operated for several decades by major companies. UK oil production peaked in 1999 and has since declined at an annual rate between 5 and 10 percent. However, in 2011, decline accelerated to an unprecedented 17.9 percent. A number of factors contribute to this, including an increase in taxation on North Sea production made without warning in March of that year (Mearns 2013). In recent years, there has been significant trading of offshore oil and gas assets from these original major companies to smaller companies. Recognizing the economic importance of oil and gas production and the ability of independent companies to extend field life and maximize economic recovery, the government of the United Kingdom of Great Britain and Northern Ireland (UK government) has facilitated the free trade in mature offshore oil and gas assets. At the same time, the government has also worked to ensure that it is not exposed to the risk of default in meeting the costs associated with decommissioning the aging infrastructure on these mature fields.

The risk to the government is that, in relation to any particular field, the participating companies at the time of decommissioning will not have sufficient assets to pay for the work. Further, although such companies have access to sufficient assets, those assets are outside UK jurisdiction, and the powers of enforcement available under the Petroleum Act 1998 may not be exercisable so as to ensure that the companies comply with their obligations. In such cases, the UK's international obligations mean that the UK government would consider itself obliged to arrange for decommissioning, and the cost may then fall on the government (DECC 2011).

2. Regulatory Structure

The Secretary of State for Energy and Climate Change (Secretary) has primary responsibility for the leasing of lands on the UK continental shelf (UKCS) and oversight of operations. The Department of Energy and Climate Change (DECC) issues production licenses for offshore exploration and production. These licenses include terms and conditions under which DECC regulates drilling, field development and production, license transfers and operatorship, and the storage and confidentiality of data. DECC also administers offshore environmental regulation and the decommissioning of offshore oil and gas installations and pipelines.

There are three primary components of decommissioning in the UK: identification of potentially responsible parties, development of abandonment programmes, and establishment of bonds to cover decommissioning costs.

2.1 Persons Potentially Responsible for Abandonment Costs

Under section 30 of the Petroleum Act 1998 and amendments in the Energy Act 2008, the following may be identified by the Secretary as potentially responsible for the decommissioning or costs of decommissioning offshore infrastructure:

(1) (a) the person having the management of the installation or of its main structure;

(b) a person to whom subsection (5) applies in relation to the installation;

(ba) a person to whom subsection (5)(a) and (5)(b) applied in relation to the installation, but who—

(i) transferred the right mentioned in that subsection to another person, and

(ii) has not obtained a consent required under the license in relation to the transfer

(c) a person outside paragraphs (a) and (b) who is a party to a joint operating agreement or similar agreement relating to rights by virtue of which a person is within paragraph (b);

(d) a person outside paragraphs (a) to (c) who owns any interest in the installation otherwise than as security for a loan;

(e) a body corporate which is outside paragraphs (a) to (d) but is associated with a body corporate within any of those paragraphs.

(5) This subsection applies to a person in relation to an offshore installation if—

(a) he has the right to exploit or explore mineral resources in any area, or to store gas in any area and to recover gas so stored;

As shown above, the Secretary can cast a very wide net to identify persons that may be liable for the cost of decommissioning, including current and past operators of offshore infrastructure, current and past license holders, parties to a joint operating agreement, those who have a financial interest in the infrastructure, and the parent companies of the above. In short, any party that is entitled to derive a financial or other benefit from the infrastructure may be held liable. Review of published decommissioning plans documented that the UK is identifying current and past operators, current and past license holders, parties to joint operating agreements, parties with financial interest and parent companies to be held liable for DR&R.

Under Section 34, a person may, in certain circumstances and following the approval of a programme, be placed under a duty to carry out that programme even though it has previously been released by the

Secretary. Also, the Secretary can place under a duty to carry out a programme any person that could have been identified as responsible since the first Section 29 notice holders were identified (in essence, the Secretary can identify persons retroactively and over time). DECC notes in its guidance that “This situation has not occurred to date and we regard it as a measure of last resort. In the first instance, the Secretary of State would expect the current section 29 notice holders to carry out the decommissioning and would only use the powers in section 34 in potential default cases which we endeavor to avoid by the use of prudent security arrangements.”

Under Section 35, the Secretary may release a Section 29 notice holder from its financial and other obligations under an abandonment programme if a person disposes of its interest in the installation(s) on a field or otherwise assigns their interest. The Secretary is under no obligation to release a Section 29 notice holder; however, if a Section 29 notice is not withdrawn, the notice holder is not liable for any new installations emplaced in the field after the assignment of their interest. However, they would be liable for any new equipment added to an installation already covered by their existing notice.

Liability for abandonment costs is joint and several. Section 36 of the Petroleum Act 1998 states that “… it shall be the duty of each of the persons who submitted [an abandonment programme] to secure that it is carried out and that any conditions to which the approval is subject are complied with.”

2.2 Abandonment Programmes

Section 29 of the Petroleum Act 1998, Preparation of Programmes, authorizes the Secretary to require persons identified in Section 30 to submit “a programme setting out the measures proposed to be taken in connection with the abandonment of an offshore installation or submarine pipeline (an “abandonment programme”).” The abandonment programme shall contain “an estimate of the cost of the measures proposed in it” and shall “either specify the times at or within which the measures proposed in it are to be taken or make provision as to how those times are to be determined.” The persons identified per Section 30 are notified by the Secretary of their duty to prepare an abandonment programme and to be bound by that programme; these persons are referred to as “section 29 notice holders.”

Section 31 notes that the Secretary may relieve a Section 29 notice holder from its responsibility to prepare an abandonment programme “if the Secretary of State has been and continues to be satisfied that adequate arrangements (including financial arrangements) have been made … that a satisfactory abandonment programme will be carried out.”

The Secretary may require Section 29 notice holders to develop an abandonment programme at any time. DECC guidance notes that discussions between Section 29 notice holders and DECC regarding the development of an abandonment programme “should commence well ahead of forecast cessation of operations. In the case of a large field with multiple facilities, this may be 3 years or more in advance. In the case of a potential derogation case it may be up to 5 years in advance.” (DECC 2011) The field- or platform-specific production horizons of the independents who take over operation from a previous owner are much shorter in most cases than the horizons of the original operator. As a result, DECC can require that abandonment programmes be developed in the early years of field operations (and even prior to the start of production), rather than waiting until later in the field's life as they traditionally have done.

The content of an abandonment programme is spelled out in Annex C to DECC's Guidance Notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998. Among other items, an abandonment programme should contain an overall cost estimate of the preferred decommissioning option and an indication of the basis on which the estimate is made. Provisions are made for protecting sensitive cost data. DECC has developed a streamlined abandonment programme template (Attachment A to this document).

Abandonment programmes are subject to approval or rejection by the Secretary. The Secretary may approve an abandonment programme with or without modifying it, either subject to conditions or unconditionally (Section 32, the Petroleum Act 1998).

Section 36 of the Petroleum Act 1998, Duty to Carry Out Programmes, notes that when a programme is approved, "it shall be the duty of each of the persons who submitted it to secure that it is carried out and that any conditions to which the approval is subject are complied with."

3. Financial Assurances Related to Decommissioning

The Petroleum Act 1998 and the Energy Act 2008 give the Secretary wide-ranging powers to ensure that persons potentially liable for decommissioning costs have the financial capability to meet their obligations:

- Section 38, Financial Resources, of the Petroleum Act 1998: The Secretary can require Section 29 notice holders to provide information and documents relating to the person's financial affairs and capability to discharge their responsibilities in carrying out the abandonment programme. The Secretary can also require Section 29 notice holders to "take such action as may be specified … within such time as may be so specified." "Such action" is not defined, but can include any measures (including the provision of financial securities) deemed necessary to satisfy the Secretary that the organization "will be capable of discharging the duty imposed on him."

- Section 73, Financial Resources etc., of the Energy Act 2008: The Secretary can require persons to submit information and documents relating to the person's financial affairs prior to the Secretary providing those persons with a notice under Section 29. The Secretary can use this information to determine "whether to give a notice under section 29 to a person in respect of an installation or pipeline" or to determine if the Secretary should impose a duty on that person to fulfill the obligations of an abandonment programme.

- Section 73, Financial Resources etc., of the Energy Act 2008: Provides for the Secretary to require from persons more specific information, which could include a detailed estimate of the costs of decommissioning, predictions of future revenue, the costs and benefits of any plans for further development, or up-to-date management accounts.

- Section 73, Financial Resources etc., of the Energy Act 2008: Amends Section 38 of The Petroleum Act 1998 and provides for the Secretary to require action (including the provision of financial security, such as a letter of credit or becoming party to a decommissioning security agreement) to be taken by a person who has been served with a notice under Section 29 or who has a duty to carry out a programme, where the Secretary is not satisfied that the person is capable of carrying out the programme.

  Under the Petroleum Act 1998, the Secretary only had the ability to require such action following the approval of a decommissioning programme. By enabling the Secretary to require action once a notice under Section 29 has been served, but in advance of programme approval, the taxpayer can be protected against the early failure of a development.

- Section 74 of the Energy Act 2008, Protection of Abandonment Funds from Creditors, inserts two new sections into the Petroleum Act 1998. New section 38A, Protection of Funds Set Aside for the Purposes of Abandonment Programme, states in part that "where any security for the performance of obligations under an approved abandonment programme has been provided by a person ("the security provider") by way of a trust or other arrangements … no regard is to be had to the Insolvency Act 1986 or any other enactment or rule of law" that would "prevent or restrict the protected assets from being applied in accordance with the trust or other arrangement" or "prevent or restrict their enforcement for the purposes of being so applied." In essence, Section 74 is designed to ensure that, in the event of the insolvency of a person responsible for a decommissioning programme or a person with obligations under that programme, the funds set aside for meeting those liabilities remain available for decommissioning and are not available to the general body of creditors.

New section 38B, Directions to Provide Information about Protected Assets, requires that persons responsible for an abandonment programme publish information regarding their relevant financial security arrangements so that creditors and potential future creditors of that person are aware of any decommissioning funds affected by the new powers to disapply insolvency legislation.

The joint and several liability for decommissioning costs, and the ability of the Secretary to pursue past owners/operators for decommissioning costs, led to a situation where a seller of a license or infrastructure would require the buyer to post financial security in an amount sufficient to cover the full cost of decommissioning. Posting such an amount can negatively impact the current accounts of smaller, independent companies, and thus serve as a barrier to entry. This situation was counter to the express policy of the UK Government to encourage the entry of smaller independent companies into the market.

Recognizing this, DECC has worked with Oil and Gas UK to develop a Decommissioning Security Agreement (DSA) as an industry- and government-approved pro forma that provides a transparent and balanced approach to the provision of decommissioning security. In addition, HM Treasury, in consultation with Oil and Gas UK and other stakeholders, has established Decommissioning Relief Deeds (DRDs) that can reduce the amount of financial security required under a DSA. These two measures are discussed in the sections below.

3.1.1 Decommissioning Security Agreements

The oil and gas industry and the UK Government have devised the DSA as an industry- and government-approved pro forma that provides a transparent and balanced approach to the provision of decommissioning security (Memery Bank 2010).

The overriding aim of a DSA is to ensure that guaranteed funds (which may include future revenues in appropriate cases) will be available to cover the decommissioning costs at all times. For example, if a company becomes insolvent before decommissioning, the security posted under the DSA would be triggered and held in trust. This security will be equal to the insolvent participant's share of the decommissioning costs reduced by an allowance for their share of any remaining oil and gas reserves and the operating expenditure that would be spent in recovering those reserves, in line with a formula contained in the DSA (DECC 2011).

The DSA is designed primarily to be entered into by all of the licensees, who are parties to a Joint Operating Agreement (JOA), and to either replace or supplement any existing provisions in a JOA regarding decommissioning security. The DSA may also be used among licensees when it is proposed that a license is assigned. In these cases, the DSA is designed to satisfy the Secretary that the relations between the outgoing party, the incoming party, and (to the extent there are any) the remaining parties, will be sufficiently well regulated and secured insofar as decommissioning liabilities are concerned. In this instance, the Secretary may wish to become a party to the DSA in order to preserve a right to control any future amendments to it (Oil and Gas UK 2009).

3.1.1.1 Acceptable Forms of Financial Security

DECC requires the parties to a DSA to provide security such as cash, irrevocable standby letters of credit (LoCs) issued by a Prime Bank, or on-demand (performance) bonds from Prime Banks or issued by an Insurer regulated under the Financial Services and Markets Act 2000. For these purposes, the security must be issued by a body established in a European Union (EU) or Organization for Economic Co-operation and Development (OECD) country with a UK lending or insurance office and which have an AA rating or better as defined by Standard and Poor's, Aa2 rating or better as defined by Moody's, or an equivalent rating by another recognized rating agency. DECC may consider proposals which do not fully meet these criteria and take account of factors such as the level of risk and decommissioning costs and the presence of other parties to the DSA.

The DECC guidance notes that parent company guarantees are generally considered an unacceptable form of security (DECC 2011).

3.1.1.2 Security Amount

DECC guidance notes that the security should provide at least 100 percent of estimated costs including site cleanup after the main removal work. DECC guidance notes that, in most cases, it will also be necessary to add a risk factor of up to 50 percent of the estimated costs to cover the uncertainties surrounding cost calculations (DECC 2011).

Per the DSA template, each year, each licensee must pay to its Trustee an amount equal to that party's share of net cost (multiplied by a risk factor) less its share of net value and less the amount of any security already provided which remains valid (for instance any cash already in the Trust Fund).

An alternative approach to this calculation is to provide for security equal to a party's share of Decommissioning Costs without any risk factor but without any credit for receipts (Oil and Gas UK 2011).

3.1.1.3 Renewal

Securities should be renewed annually, 2 months before the next period of security is due to commence.

In the event of the failure by any party to renew security before the next period, that party would be in default financial security would be triggered, and the money drawn down and deposited in a regulated Trust Fund to accrue interest until it is needed to pay for decommissioning costs.

3.1.1.4 Audit

DECC guidance notes that estimates of decommissioning costs and of the net value of remaining recoverable reserves used to calculate the required levels of security must be carried out at least every 3 years and may be required annually depending on the project timescales. An independent third-party expert approved by DECC must verify this audit process.

The Oil and Gas UK guidance does not specify a time period for reviews or audits, except to note that they should be conducted "every specified number of years - as a variation on this, reviews may be every few years initially changing to annual reviews during the Later Run-Down Period when information is likely to change more frequently." The guidance also notes that reviews may take place in intervening years "if the Operator believes that there has been a change in Net Cost or Net Value of more than 10 or 20 percent."

3.1.2 Decommissioning Relief Deed

As presented above, under UK law, owners of offshore infrastructure at the end of its useful life are jointly and severally liable for decommission costs. If the owners default, a wide range of people (including former owners) are also potentially liable to pay for decommissioning. As a result, co-ventures in oil fields often enter into DSAs as discussed previously. Under the DSA, each owner provides security to the others against the risk of defaulting on its decommissioning obligations. Oil companies selling interests in fields can also require such security from those purchasing their interest. Security is usually provided in the form of an LoC from a bank, and the bank will often require collateral from the party providing the security.

Tax relief is available for decommissioning costs when they are incurred. However, uncertainties surrounding the amount of relief that will be available at the time the costs are incurred means that DSAs typically require security to be calculated "gross," without any allowance for tax relief. This significantly increases (by a factor of four in some cases) the funds tied up in security which would otherwise have been available to invest, and prices some parties out of the market for assets (Aldersey-Williams et al. 2013).

Recognizing that uncertainty regarding decommissioning tax relief was serving as a barrier to the entry of independent companies into the offshore UK, HM Government engaged industry to develop the DRD. The DRD is a contract between the Government and companies operating in the UK and UKCS that provides certainty on the tax relief they will receive when decommissioning assets (a copy of the generic DRD is provided in Attachment C).

The DRD provides that, in such circumstances as are specified in the agreement, if the amount of tax relief in respect of any decommissioning expenditure incurred by the qualifying company is less than an amount determined in accordance with the agreement (the reference amount), the difference is payable to the company. The DRD essentially "locks in" the amount of tax relief available at the time of decommissioning in the case that the amount of tax relief is less (i.e., taxes are higher) in future years.

The benefits of the DRD extend to affiliates of the DRD-holder; therefore, all persons involved in a given development and party to a DSA may reduce the amount of financial security they must post. The effect of this change will be to encourage investment by existing owners of assets, increase asset trades, and free up capital currently put aside to provide security, thereby extending the productive life of fields. An analysis conducted by Oil and Gas UK suggests that decommissioning certainty will unlock new investment of about £40 billion, generate an additional 1.7 billion barrels of oil and gas and, over the next 5 years alone, the Exchequer could receive an extra £1 billion in tax revenue (Aldersey-Williams et al. 2013).

SOURCES CITED

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APPENDIX A

Streamlined Abandonment Programme Template

Department of Energy & Climate Change

Streamlined Decommissioning Programme(s) Template

(Non-Derogation Cases)

Document Control

Insert Tables of Document Revisions as per example below

Approvals

	Name	Signature	Date
Prepared by	K Tucker/G Cooper		28/09/10
Reviewed by	P. Cooper		28/09/10
Approved by	J Sewell		30/09/10

Revision Control

Revision No	Reference	Changes/Comments	Issue Date
0	Develop outline programme		30 Jan 2009
1	First draft		6 Feb 2009
	…		
	…		
5.5	Final Issued Version		30 Sept 2010

Distribution List

Name	Company	No of Copies
……..		

Department of Energy & Climate Change

DECOM North Sea

Contents

Delete options and brackets where appropriate. Remove red help text throughout document

Terms and Abbreviations

Include a table of the terms and abbreviations used in the document (examples in blue below).

Abbreviation	Explanation
DECC	Department of Energy and Climate Change
ES	Environmental Statement
CA	Comparative Assessment

Figures and Tables

Include a table of Figures and Tables used in the document.

Appendices

Include a table of the Appendices which are to be included as part of this document (example in blue below).

Appendix	Description	Page
1	Statutory Consultee Correspondence	32

Note: The Environmental Statement (ES) (otherwise known as the Environmental Impact Assessment or EIA) and any Comparative Assessment (CA) for pipelines are separate, referenced documents in support of the decommissioning programme(s). They should not be included as an Appendix but listed in Section 7 (Supporting Documents).

1 EXECUTIVE SUMMARY

1.1 Decommissioning Programme/ Combined Decommissioning Programmes

This document contains ______ decommissioning programme(s) for ______installation(s) and _______ pipeline(s).

Combined Decommissioning Programmes: Please provide a clear statement confirming that there is a separate programme for each set of associated notices served under Section 29 of the Petroleum Act 1998.

1.2 Requirement for Decommissioning Programme(s)

Delete appropriate paragraph below if only one decommissioning programme.

Installation(s):
In accordance with the Petroleum Act 1998, the Section 29 notice holders of the ________________ installation(s)/field (see Table 1.2) are applying to the Department of Energy and Climate Change to obtain approval for decommissioning the installations detailed in Section 2.1 and 2.2 of this programme. (See also Section 8 - Partner Letter(s) of Support).

Pipeline(s):
In accordance with the Petroleum Act 1998, the Section 29 notice holders of the ________________ pipelines (see Table 1.4) are applying to the Department of Energy and Climate Change to obtain approval for decommissioning the pipelines detailed in Section 2.3 of this programme. (See also Section 8 – Partner Letter(s) of Support).

In conjunction with public, stakeholder and regulatory consultation, the decommissioning programme(s) is/are submitted in compliance with national and international regulations and DECC guidelines. The schedule outlined in this document is for a _____ year decommissioning project plan due to begin in _________________.

1.3 Introduction

*Insert introductory paragraphs outlining the background of the decommissioning proposal with information on topsides, jacket and pipelines (where applicable). Freeform text as per example paragraphs in blue below. **(Suggested maximum of 250 words)***

The Welland Field is located in the Southern Basin of the UKCS in license block 53/4a. Welland was discovered in 1983 and consists of three gas reservoirs with condensate traces. It received Annex B approval in 1989 for a single platform remotely operated from Thames platform. The platform was installed and production started in 1990. Production ceased in 2003 due to excessive water rates and equipment failures. Cessation of Production notification was submitted in 2004.

Welland Platform is a 1000t topside minimum facilities structure in 37m water depth. It was designed and operated as a normally unattended satellite installation. Gas was exported to the nearby Thames complex. Subsea tie-backs to 3 remote wells comingle with production from the 2 platform wells.

Following public, stakeholder and regulatory consultation, the decommissioning programme(s) is/are submitted without derogation and in full compliance with DECC guidelines. The decommissioning programme(s) explains the principles of the removal activities and is supported by an environmental impact assessment.

1.4 Overview of Installation(s)/Pipeline(s) Being Decommissioned

1.4.1 Installation(s)

Table 1.1: Installation(s) Being Decommissioned			
Field name(s)		**Quad/Block**	
Surface Installation(s)		**Subsea Installation(s)**	
Total Number	Type*	Total Number	Type**
Number of Wells		**Drill Cuttings Pile(s)**	
Platform	Subsea	Number of Piles	Total Est volume (m^3)
Production Type *(Oil/Gas/Condensate)*	**Water Depth (m)**	**Distance from nearest UK coastline (km)**	**Distance to Median Line (if less than 5km)**

** fixed steel jacket / floating facility / FPSO / etc. ** Template/manifold / WHPS / Manifold etc.*

Table 1.2 Installation(s) Section 29 Notice Holders Details		
Section 29 Notice Holder(s)	**Registration Number**	**Equity Interest (%)** *If zero show 0%*

1.4.2 Pipeline(s)

Table 1.3: Pipeline(s) Being Decommissioned		
Number of Pipeline(s)		**(See Table 2.3)**

Table 1.4: Pipeline(s) Section 29 Notice Holders Details		
Section 29 Notice Holder(s)	**Registration Number**	**Equity Interest (%)** *If zero show 0%*

1.5 Summary of Proposed Decommissioning Programme(s)

Complete Table 1.5, as per examples in blue below.

Table 1.5: Summary of Decommissioning Programme(s)		
Selected Option	**Reason for Selection**	**Proposed Decommissioning Solution**
1. Topsides		
Complete removal and re-use *(or N/A if subsea installation(s) only or pipeline(s) only programme)*	Perenco subsidiary indicated that Welland installation suitable for development of new well outside UKCS waters.	Cleaned equipment refurbished for re-use where possible. Remove wholly by HLV. Equipment which cannot be re-used will be recycled or other disposal routes as appropriate.
2. Jacket(s)/Floating Facility (FPSO etc.)		
Complete removal and recycling *(or N/A if a subsea installation(s) only or pipeline(s) only programme)*	Leaves clean seabed, removes a potential obstruction to fishing operations and maximises recycling of materials	May need to be cut at the -11m level (26m above sea-bed) to allow re-use at proposed new location. Legs will be removed with piles and cut on vessel/ barge decks or at an onshore location. Lower 26M of the jacket and piles and subsea wellhead protection frames will be transported ashore for recycling.
3. Subsea Installation(s)		
Wellhead protection frames will be removed by HLV or crane vessel with crane *(or N/A if none present or pipeline(s) only programme)*	To remove all seabed structures and leave a clean seabed	Wellhead protection frames will be removed along with the top sections of piles. Piles for wellhead protection structures and jacket structure will be removed to -3 metres.
4. Pipelines, Flowlines & Umbilicals		
Flush and leave buried in situ *(or N/A if an installation(s) only programme)*	Minimal seabed disturbance, lower energy usage, reduced risk to personnel	The 16 inch pipeline, 3inch piggy-back line, three 8 inch flowlines and three 4" umbilicals will be left in situ, with the cut ends re-buried as recommended by the Fishermen's Federation. Surveys indicate pipelines and umbilicals will remain buried with flooding. Degradation will occur over a long period within seabed sediment, not expected to represent a hazard to other users of the sea.
5. Wells		
Abandoned in accordance with Oil & Gas UK Guidelines for the Suspension and abandonment of Wells	Meets DECC regulatory requirements	A PON5/PON15/MCAA application under the relevant regulations will be submitted in support of works carried out.
6. Drill Cuttings		
Leave in place to degrade naturally	Cuttings pile is small, thin and widely dispersed and falls below both of OSPAR 2006/5 thresholds	Left undisturbed on seabed
7. Interdependencies *Provide (as appropriate) a comment on any interactions between the different elements of the decommissioning programme e.g. drill cuttings/drilling templates etc.*		
Whole of jacket can be removed; cuttings pile has little influence on jacket options. Jacket piles can be cut with minimal disturbance to the thin layer of cuttings around bottoms of legs. Small amounts of sediment and cuttings may have to be displaced to allow pile cutting.		

1.6 Field Location Including Field Layout and Adjacent Facilities

Figure 1.1: Field Location in UKCS

Include a figure which shows the field location in UKCS (see example)

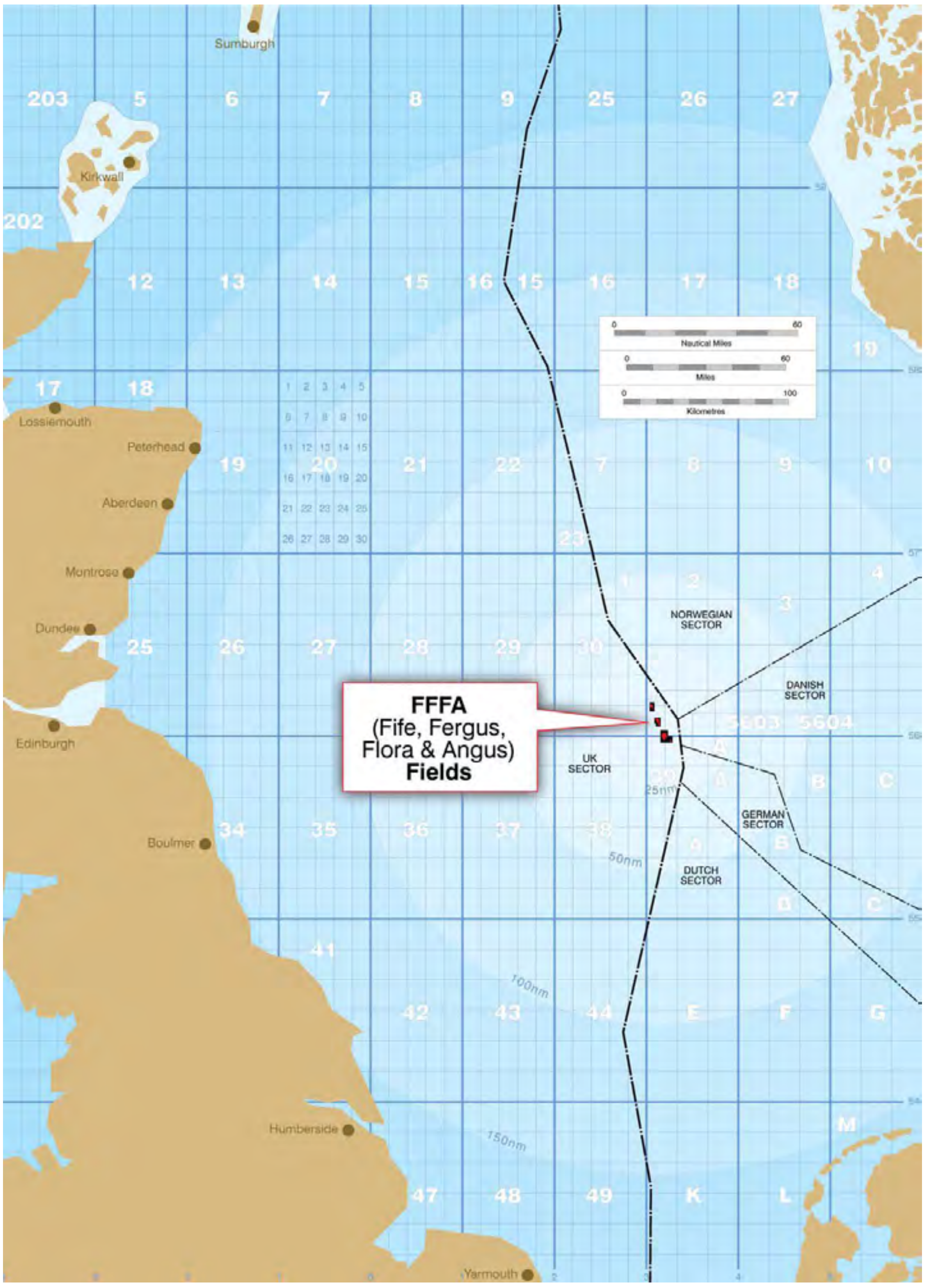
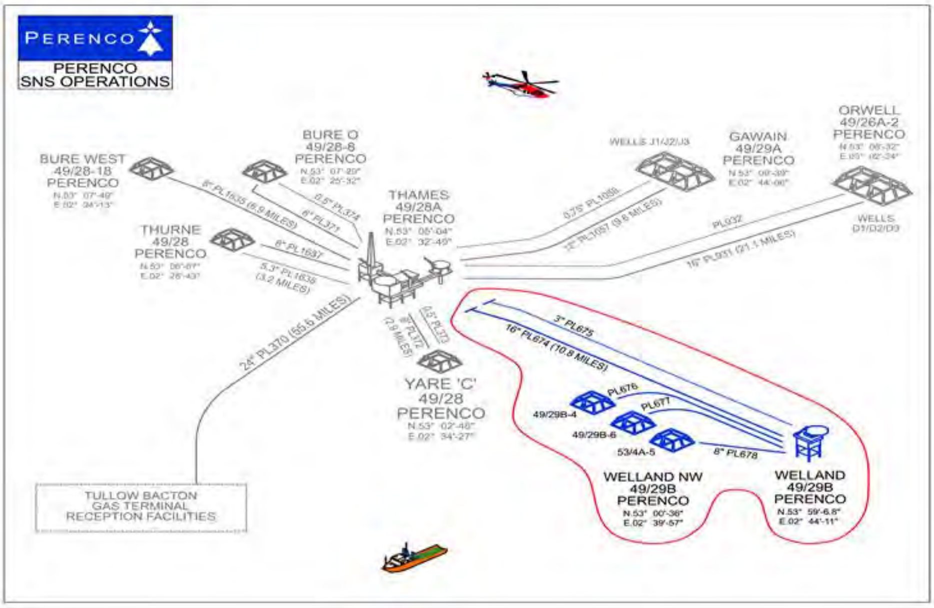


Figure 1.2: Field Layout

Insert a diagram to show the layout of the field, including subsea installation(s) (see example)



Note: Adjacent facilities refer to those potentially impacted by this programme (see DECC Guidance Notes for Industry: Version 6).

Complete Table 1.6 (examples in blue below) listing any adjacent facilities (e.g. platforms, pipelines, pipeline crossings and telephone cables).

Table 1.6 Adjacent Facilities					
Owner	**Name**	**Type**	**Distance/Direction**	**Information**	**Status**
Perenco	Thames	Platform	17km North West	Gas/liquids processing, MEG and control system links for Welland, onward export to Bacton	*e.g. Operational; Out-of-use; Suspended*
Perenco	PL674	16" Pipeline	From Welland to Thames (17km NW)	Crosses 2 disused cables and Sean 30" gas pipeline to Bacton	
Perenco	Gawain	Subsea Well umbilical	500m	From Gawain to Thames, crosses over Welland/Thames pipeline	
Impacts of Decommissioning Proposals					
*If appropriate describe any impacts the adjacent facilities may have on the decommissioning proposals. **(Suggested maximum of 50 words)***					

Figure 1.3: Adjacent Facilities

Insert a diagram to show the specified adjacent facilities (see example)

1.7 Industrial Implications

Provide a summary describing how the contract/procurement strategy is to be undertaken. ***(Suggested maximum of 250 words)***

2 DESCRIPTION OF ITEMS TO BE DECOMMISSIONED

2.1 Installation(s): Surface Facilities (Topsides/Jacket(s)/FPSO etc.)

*Complete Table 2.1 (example in blue below). **Repeat for each installation in the programme**. Insert N/A (not applicable) or N/D (no data) as appropriate.*

Table 2.1: Surface Facilities Information								
Name	Facility Type*	Location** ED50 Format	Topsides/Facilities		Jacket (if applicable)			
			Weight (Te)	No of modules	Weight (Te)	Number of legs	Number of piles	Weight of piles (Te)
Welland South Platform	Small fixed steel	58^0 03' 2.78"N 00^0 21' 5.72"E	942	1	570	3	3	300

**fixed steel jacket / floating facility / FPSO / etc.*
***Location to be given in ED50 or WGS84 format.*

2.2 Installation(s): Subsea including Stabilisation Features

Complete Table 2.2 Insert n/a if not applicable. See example in blue below

Table 2.2: Subsea Installations and Stabilisation Features				
Subsea installations* including Stabilisation Features	Number	Size/Weight (Te)	Location** ED50 Format	Comments/Status***
Wellheads	2	1 x 31.96 tonnes 1 x 4.5 tonnes	1. 58^0 03' 2.78"N 00^0 21' 5.72"E 2. 58^0 02' 59.9"N 00^0 20' 58.2"E	Both wells are suspended and will undergo plug and abandonment. Neither structure is piled to seabed
Manifold	1	15m x 6m x 5m 105 tonnes	58^0 04' 24"N 00^0 26' 10"E	Structure is secured to the seabed by four steel piles.
Protection Frame(s)	n/a			
Concrete mattresses	n/a			
Grout bags	n/a			
Formwork	n/a			
Frond Mats	n/a			
Rock Dump	n/a			
Other (*describe briefly*)	n/a			

**Template/manifold / WHPS / Manifold etc.*
***Location to be given inED50 or WGS84 format.*
****Indicate in comments/status if piled.*

2.3 Pipelines Including Stabilisation Features

Complete Tables 2.3 and 2.4 with details of pipelines, flowlines and umbilicals. Lines laid as FEPA Exempt which do not have a PWA Pipeline Number should also be included (example in blue below).

Table 2.3: Pipeline/Flowline/Umbilical Information

Description	Pipeline Number (as per PWA)	Diameter (inches)	Length (km)	Description of Component Parts[1]	Product Conveyed[2]	From – To End Points	Burial Status[3]	Pipeline Status[4]	Current Content[5]
Export line	PL674	16"	17.5	Concrete coated steel	Gas	Welland South Platform – SSIV on Thames AW Platform	Trenched with 7m section exposed	Operational	Hydrocarbon
MEG line	PL675	3"	17.5	Composite Flexible	Chemicals	Thames AW Platform – Welland South Platform	Surface laid No freespans	Operational	Chemicals
Well 2 Subsea flowline	PL678	8"	4.2	Concrete coated steel	Gas	Well-53/04a- 5 – Welland South Platform	Trenched and buried	Operational	Hydrocarbon
Well 2 Subsea control umbilical & MEG line	PL681	4" & 0.75"	4.2	Composite Flexible	Chemicals	Welland South Platform - Well-53/04a- 5	Trenched and buried	IPR	Chemicals
FTP	FEPA Exempt		0.17	Composite Flexible		DC1 – U61R		Out of Use	

[1] e.g. Concrete; Steel; Umbilical; Flexible; Bundle
[2] e.g. Oil; Gas; Water; Chemicals
[3] e.g. Laid on seabed; Trenched; Trenched and Buried; Spanning
[4] e.g. Operational; Out-of-use; Interim Pipeline Regime (IPR)
[5] e.g. Cleaned; Flushed; Hydrocarbons and/or Chemicals in line

Table 2.4: Subsea Pipeline Stabilisation Features				
Stabilisation Feature	**Total Number**	**Weight (Te)**	**Location(s)**	**Exposed/Buried/Condition**
Concrete mattresses	5	6 tonnes each	At Pipeline crossing points	Can only be recovered when cross over lines are decommissioned
Concrete mattresses	20	10 x6 tonnes 10 x 8 tonnes	PL674	Exposed
Grout bags	80	25kg each		Exposed
Formwork	n/a			
Frond Mats	n/a			
Rock Dump	n/a	2000	2 Locations on PL674	
Other *(describe briefly)*	n/a			

2.4 Wells

Complete Table 2.5 (examples in blue below)

Table 2.5 Well Information			
Platform Wells	**Designation[1]**	**Status**	**Category of Well**
211/19a-M69	Oil Production	Live	PL 1-1-3
211/19a-M56	Water Injection	Live	PL 2-3-3
Subsea Wells			
211/19-MS4	Oil Production	Abandoned	SS 1
211/19-MS2	Oil Production	Suspended	SS4

[1] e.g. Production; Injection; Oil; Gas

For details of well categorisation see OGUK Guidelines for the Suspension or Abandonment of Wells. Issue 4, July 2012.

2.5 Drill Cuttings

(See Section 3.6 for further information)

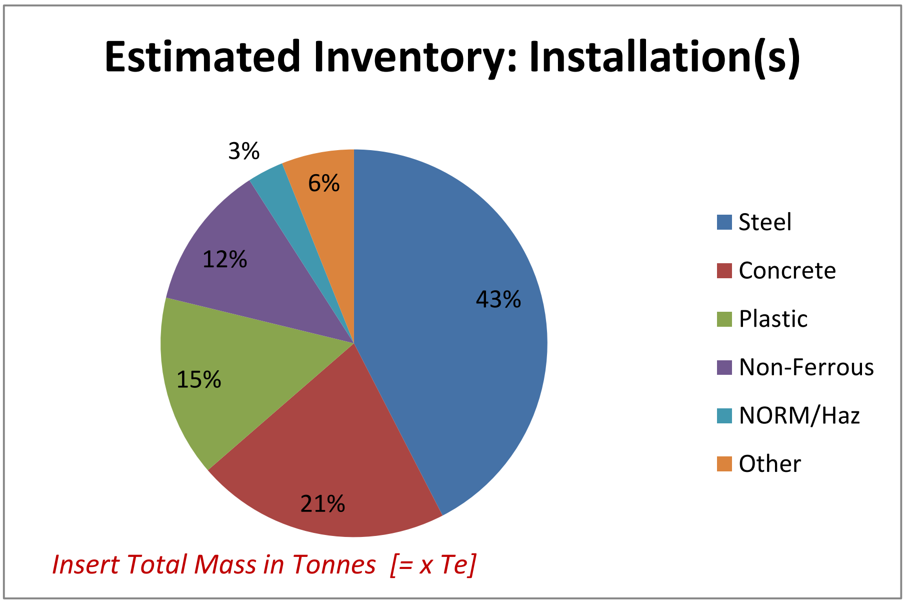
Complete Table 2.6 for each cuttings pile (examples in blue below)

Table 2.6: Drill Cuttings Pile(s) Information		
Location of Pile Centre (Latitude/Longitude)	**Seabed Area (m^2)**	**Estimated volume of cuttings (m^3)**
Schiehallion Central	8371	11352
Schiehallion West	6731	7224
Schiehallion North	4476	1548
Loyal	5501	4128

2.6 Inventory Estimates

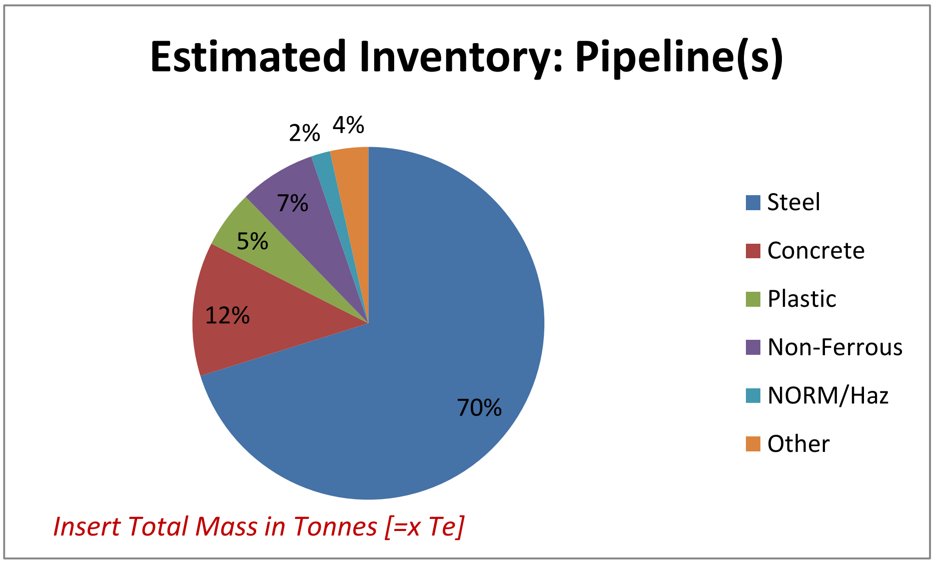
Provide a table or graph (see pie chart example shown) giving the inventory estimates for the decommissioning programme(s) contained in this document. Refer to tables or data in the supporting Environmental Statement.

Figure 2.1: Pie Chart of Estimated Inventories (Installations)



Reference the Environmental Statement for detailed data.
NORM/Hazardous Waste - reference the supporting evidence in ES.

Figure 2.2: Pie Chart of Estimated Inventory (Pipelines)



Reference the Environmental Statement for detailed data
NORM/Hazardous Waste – reference the supporting evidence in ES.

3. REMOVAL AND DISPOSAL METHODS

In line with the waste hierarchy, the re-use of an installation (or parts thereof) is first in the order of preferred decommissioning options. DECC is keen to encourage the re-use of facilities wherever this is practical and will expect the decommissioning programme(s) to demonstrate that the potential for re-use has been examined fully.

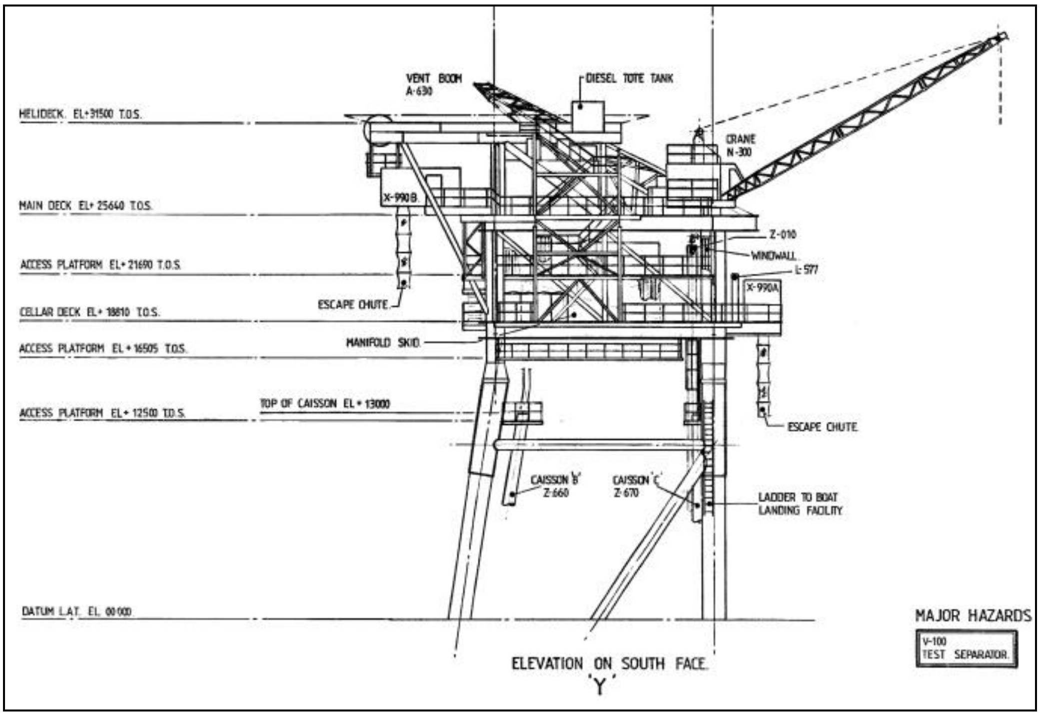
The programme(s) should therefore include a statement of how the principles of the waste hierarchy will be met, including the extent to which the installation(s) (or parts thereof) will be reused, recycled or scrapped. (Suggested maximum 250 words)

3.1 Topsides

Indicate N/A if no topsides. Briefly describe the topsides and decommissioning methodology (see example in blue below). Insert a diagram to illustrate. ***Repeat for each topside in the programme(s)****. Note: For Floating Facilities, provide a brief description of the decommissioning method.* ***(Suggested maximum 150 words)***

Topsides Description: The Welland Topside Structure comprises three levels and weighs 942 Te. The lower level is the cellar deck with process, hydraulic pressure equipment and wells. The 20m x 14m main deck supports the control room, generation and temporary accommodation facilities with a pedestal crane and vent boom. The main deck is 25.6m above sea level. A helideck is located at the upper level.

Figure 0.1: Diagram of Topsides



Preparation/Cleaning: *Outline in Table 3.1 the methods that will be used to flush, purge or clean the topsides offshore, **prior to removal to shore**, (see examples in blue below).*

Table 3.1: Cleaning of Topsides for Removal		
Waste Type	**Composition of Waste**	**Disposal Route**
Onboard hydrocarbons	Process fluids, fuels and lubricants	Drained and transported ashore for re-use/disposal
Other hazardous materials	NORM, LSA Scale, Any radioactive material, instruments containing heavy metals, batteries	Transported ashore for re-use/disposal by appropriate methods
Original paint coating	Lead-based paint	May give off toxic fumes / dust if flame-cutting or grinding/blasting is used so appropriate safety measures will be taken
Asbestos and Ceramic Fibre		Appropriate control and management will be enforced

Removal Methods: *Topsides must be completely removed and returned to shore. Possible methods should be outlined in Table 3.2 (see examples in blue below). Tick which methods you are considering for topsides decommissioning. Then briefly describe those applicable to your project.*

Table 3.2: Topsides Removal Methods	
1) HLV (semi-submersible crane vessel) ☐ 2) Monohull crane vessel ☐ 3) SLV ☐ 4) Piece small ☐ 5) Other *(describe briefly)* ☐	
Method	**Description**
Single lift removal by SLV/HLV	Removal of topsides as complete units and transportation to shore for re-use of selected equipment, recycling, break up, and/or disposal
Modular removal and re-use/recycle by HLV	Removal of parts/modules of Topsides for transportation and reuse in alternate location(s) and/or recycling/disposal
Offshore removal 'piece small' for onshore reuse/disposal	Removal of topsides by breaking up offshore and transporting to shore using work barge. Items will then be sorted for re-use, recycling or disposal
Proposed removal method and disposal route (Make sure this section appears in BOLD font)	***State the method you propose for removing and disposing of the topsides, recognising any potential issues regarding trans-frontier shipment of waste. Highlight if more than one option is being carried forward into competitive tendering. If applicable add the phrase – "A final decision on decommissioning method will be made following a commercial tendering process." (Suggested maximum of 50 words).***

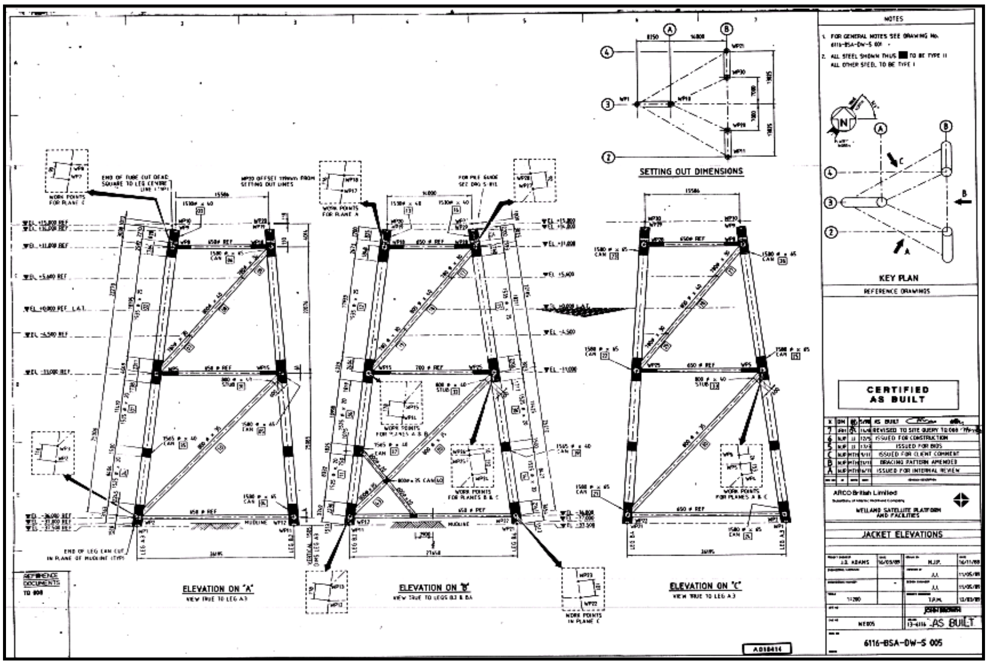
3.2 Jacket(s)

3.2.1 Jacket Decommissioning Overview

Indicate N/A if no Jacket. Provide an overview of the Jacket(s) Decommissioning methods. See example in blue below. Outline any special considerations affecting the options. Insert a diagram to illustrate. ***Repeat for each jacket in the programme(s)***. ***(Suggested maximum 150 words)***

The jacket legs may need to be cut at the -11m level (26m above sea-bed) to allow re-use of the topsides by a Perenco subsidiary at a proposed new location. Although the full engineering process is not yet finalised, it is envisaged that the Legs will be removed with piles in completeness and then cut on the Vessel/barge decks or at an onshore location to the required length. The lower 26M of the jacket and piles and the subsea wellhead protection frames will be transported ashore for recycling.

Figure 3.2: Jacket Elevation



3.2.2 Jacket Removal Methods

Tick the different methods that you are considering for the removal and disposal of the jacket. Complete Table 3.3 (examples in blue below) to describe how the jacket would be removed completely and returned to shore. Any piles should be severed below the natural seabed level at such a depth to ensure that any remains are unlikely to become uncovered. The depth will in the main depend upon the prevailing seabed conditions and currents (typically 2-3 metres).

Table 3.3: Jacket Decommissioning Methods	
1) HLV (semi-submersible crane vessel) ☐ 2) Monohull crane vessel ☐ 3) SLV ☐ 4) Piece small ☐ 5) Other – *(describe briefly)* ☐	
Method	**Description**
Removal and re-use	Removal of jacket for transportation to alternate site. Removal and disposal/recycling onshore of the lower 26m and piles to -10ft below sea-bed.
Onshore Disposal using HLV	Removal of the jacket as complete unit and transport ashore for break up, recycling and/ or disposal. Re-use of selected equipment would take place where practicable.
Onshore disposal using 'piece small'	Remove jacket in several pieces using attendant work barge and transport to shore yard.
Proposed removal method and disposal route (this section should appear in BOLD font)	***State the method you propose for removing and disposing of the jacket, recognising any potential issues regarding the trans-frontier shipment of waste. Highlight if more than one option is being carried forward into competitive tendering. If applicable add a phrase similar to – "A final decision on decommissioning method will be made following a commercial tendering process". (Suggested maximum of 50 words)***

3.3 Subsea Installation(s) and Stabilisation Feature(s)

Outline in Table 3.4 how the items will be decommissioned (examples in blue below). If mattresses are buried to a depth of 0.6m DECC would consider a proposal in the form of a comparative assessment to leave the mattresses in situ (robust evidence of the mattress burial status should be submitted with the comparative assessment).

Table 3.4: Subsea Installation(s) and Stabilisation Feature(s)			
Subsea installation(s) and stabilisation feature(s)	**Number**	**Option**	**Disposal Route (if applicable)**
Wellhead(s)	2	Full recovery as part of MODU campaign to P&A wells	Return to shore for reuse or recycling
Manifold(s)	1	Full recovery	Return to shore for reuse or recycling
Template(s)			
Protection Frame(s)			
Concrete mattresses			
Grout bags			

Formwork			
Frond Mats			
Rock Dump			
Other (*describe briefly*)			

3.4 Pipelines

Decommissioning Options: *In Table 3.5 summarise the pipeline(s) or pipeline groups that fall within the decommissioning programme. (See examples in blue below). Include a cross reference to Table 2.3. Remedial rock-dump is not DECC's preferred decommissioning solution and should only be selected following discussion with DECC and if a comparative assessment shows this is the best outcome and other options are not feasible.*

*Key to Options:

1) Remove - reverse reeling	2) Remove - Reverse S lay	3) Trench and bury
4) Remedial removal	5) Remedial trenching	6) Partial Removal
7) Leave in place	8) Other *(describe briefly)*	9) Remedial rock-dump

Table 3.5: Pipeline or Pipeline Groups Decommissioning Options			
Pipeline or Group (as per PWA)	**Condition of line/group** (Surface laid/Trenched/ Buried/ Spanning)	**Whole or part of pipeline/group**	**Decommissioning Options* considered**
PL1	Untrenched	Part. Section within 500m zone of the Thames AW Platform will be decommissioned at a later date.	*Show which options are being considered by inserting relevant number(s) from the list above i.e.* 1, 3, 6
PL2, PL3, PL4	Trenched, buried	Whole of pipelines	2, 5, 9

Comparative Assessment Method: *Briefly outline the method used to undertake a Comparative Assessment in line with the requirements of DECC Guidelines. Cross reference to Comparative Assessment document.* ***(Suggested maximum of 100 words)***

Outcome of Comparative Assessment: *Produce a table similar to example in Table 3.6 below for each pipeline or pipeline group, summarising the outcome of the Comparative Assessment. Identify the recommended option, and briefly present your justification for this recommendation. Cross-reference any separate Comparative Assessment document.* ***Repeat for each pipeline/pipeline group.***

Table 3.6: Outcomes of Comparative Assessment		
Pipeline or Group	**Recommended Option***	**Justification**
PL1	Option 3	Line condition made lifting impractical; burial will remove snagging risk for fishermen.
PL2, PL3, PL4	Option 9	Already trenched and buried to 0.7m, stable, no snagging hazards

3.5 Pipeline Stabilisation Feature(s)

Outline in Table 3.6 how the items will be decommissioned (examples in blue below). If mattresses are buried to a depth of 0.6m DECC would consider a proposal in the form of a comparative assessment to leave the mattresses in situ (robust evidence of the mattress burial status should be submitted with the comparative assessment).

Table 3.6: Pipeline Stabilisation Feature(s)

Stabilisation feature(s)	Number	Option	Disposal Route (if applicable)
Concrete mattresses	20 5	Full recovery. To remain in situ until pipeline crossings decommissioned.	Recover to shore. n/a.
Grout bags	80	Full recovery.	To shore for disposal in landfill.
Formwork			
Frond Mats			
Rock Dump (te)	2000te	To remain in place.	n/a.

3.6 Wells

Provide a short statement, similar to the example in blue below, to indicate your approach to well plug and abandonment. ***(Suggested maximum of 150 words)***

Table 3.7: Well Plug and Abandonment
The wells which remain to be abandoned, as listed in Section 2.4 (Table 2.5) will be plugged and abandoned in accordance with Oil and Gas UK Guidelines for the suspension and abandonment of wells. A PON5/PON15/MCAA Application will be submitted in support of any such work that is to be carried out.

3.7 Drill Cuttings

Drill Cuttings Decommissioning Options: *OSPAR recommendation 2006/5 has indicated that if the oil release rate from a cuttings pile is less than 10Te/yr and the area persistence is less than 500 km^2years then the best environmental option for the management of the pile is to leave it in place undisturbed to degrade naturally.*
Complete Table 3.8 to give details of each of the cuttings pile(s). Repeat for each pile and delete or add extra columns as appropriate. Note any interactions between the cuttings pile(s) and jacket removal.

Table 3.8 Drill Cuttings Decommissioning Options				
How many drill cuttings piles are present?				
Tick options examined: ☐Remove and re-inject ☐Leave in place ☐Cover ☐Relocate on seabed ☐Remove and treat onshore ☐Remove and treat offshore ☐Other *(describe briefly)*				
Review of Pile characteristics	**Pile 1**	**Pile 2**	**Pile 3**	**Pile 4**
How has the cuttings pile been screened? (desktop exercise/actual samples taken) – *delete as necessary*	Y/N	Y/N	Y/N	Y/N
Dates of sampling (if applicable)				
Sampling to be included in pre-decommissioning survey?	Y/N	Y/N	Y/N	Y/N
Does it fall below both OSPAR thresholds?	Y/N	Y/N	Y/N	Y/N
Will the drill cuttings pile have to be displaced in order to remove the jacket?	Y/N	Y/N	Y/N	Y/N
What quantity (m^3) would have to be displaced/removed?				
Will the drill cuttings pile have to be displaced in order to remove any pipelines?	Y/N	Y/N	Y/N	Y/N
What quantity (m^3) would have to be displaced/removed?				
Have you carried out a Comparative Assessment of options for the Cuttings Pile?	Y/N	Y/N	Y/N	Y/N

Comparative Assessment Method: *Briefly outline the method used to undertake a Comparative Assessment in line with requirements of OSPAR recommendation 2006/5 (if applicable). Cross reference to the Comparative Assessment document.* ***(Suggested maximum of 100 words)***

Outcome of Comparative Assessment: *Provide a brief summary of the outcome of the Comparative Assessment for each cuttings pile and of the proposed action to deal with the pile.* ***(Suggested maximum of 100 words for each pile)***

3.8 Waste Streams

Provide a summary in Table 3.9 (similar to example in blue below) describing how the main waste streams arising from the proposed programme(s) would be managed. If applicable, recognise any potential issues regarding the trans-frontier shipment of waste. Also complete Table 3.10 detailing the planned final disposition of the inventories from the installation(s) and pipeline(s).

Table 3.9: Waste Stream Management Methods

Waste Stream	Removal and Disposal method
Bulk liquids	Removed from vessels and transported to shore. Vessels, pipework and sumps will be drained prior to removal to shore and shipped in accordance with maritime transportation guidelines. Further cleaning and decontamination will take place onshore prior to recycling / re-use.
Marine growth	Removed onshore. Disposed of according to guidelines.
NORM/LSA Scale	NORM may be partially removed offshore under appropriate permit.
Asbestos	Will be contained and taken onshore for disposal.
Other hazardous wastes	Will be recovered to shore and disposed of under appropriate permit.
Onshore Dismantling sites	Appropriate licenced sites will be selected. Facility chosen by removal contractor must demonstrate proven disposal track record and waste stream management throughout the deconstruction process and demonstrate their ability to deliver innovative recycling options.

Table 3.10 Inventory Disposition

	Total Inventory Tonnage	Planned tonnage to shore	Planned left *in situ*
Installations			
Pipelines			

Include a statement/graph/table giving your aspirations for the percentages of materials recovered to shore that will be reused, recycled or disposed of to landfill. Refer to the appropriate sections of the ES to provide additional detail. ***(Suggested maximum of 100 words)***

4 ENVIRONMENTAL IMPACT ASSESSMENT

4.1 Environmental Sensitivities

Complete Table 4.1 to describe the important/sensitive features of the receiving environment(s) in the area(s) in which the decommissioning activities will take place. Reference details in the ES, which should be cited as a supporting document. (Discuss with DECC whether an area- or a field-specific ES is required). ***(Suggested maximum of 100 words for each section)***

Table 4.1: Environmental Sensitivities

Environmental Receptor	Main Features
Conservation interests	
Seabed	
Fish	
Fisheries	
Marine Mammals	
Birds	
Onshore Communities	
Other Users of the Sea	
Atmosphere	

4.2 Potential Environmental Impacts and their Management

Environmental Impact Assessment Summary:

Provide a summary of the main impacts identified in the ES, taking into account feedback from consultees - see example in blue below. ***(Suggested maximum of 250 words)***

Overview: Although there is expected to be some environmental impact during the decommissioning of the Welland infrastructure (53/4a, 49/28a and 49/29b), long term environmental impacts from the decommissioning operations are expected to be negligible. In addition, incremental cumulative impacts and trans-boundary effects associated with the planned decommissioning operations are expected to be negligible. There will be no planned use of explosives during these activities. We acknowledge that there will be a requirement for an environmental protection plan to be produced and submitted to DECC should this plan change.

Complete Table 4.2 identifying the main environmental impacts associated with decommissioning each of the facilities and summarising how these impacts will be managed. ***(Suggested maximum of 100 words for each section)***

Table 4.2: Environmental Impact Management		
Activity	**Main Impacts**	**Management**
Topsides Removal		
Jacket(s) /Floating Facility Removal		
Subsea Installation(s) Removal		
Decommissioning Pipelines		
Decommissioning Stabilisation Features		
Decommissioning Drill Cuttings		

5 INTERESTED PARTY CONSULTATIONS

Consultations Summary: ***(This section should be updated when the consultation phase is completed)***
1) Summarise key comments received to date from statutory consultees (similar to example in blue below). Provide copies of the public notice and correspondence from statutory consultees as an Appendix.
2) Include brief summaries of other consultations you have undertaken to date and reference any supporting documents. Under "Response" indicate how stakeholder concerns have been addressed and/or influenced your decision-making process. Updates should be provided to DECC as consultations progress.

Table 5.1 Summary of Stakeholder Comments		
Stakeholder	**Comment**	**Response**
National Federation of Fisherman's Organisations	"Dismantling process … presents an ongoing danger to fishermen … Perenco must ensure arrangement in place … which updates risk assessment"	Regular risk assessments to be agreed and discussed with NFFO
Scottish Fishermen's Federation		
Northern Ireland Fishermen's Federation		
Global Marine Systems Limited		
Public		

6 PROGRAMME MANAGEMENT

6.1 Project Management and Verification

Provide a summary of the project management/verification which will be undertaken, similar to the example in blue below. ***(Suggested maximum of 100 words)***

A Perenco Project Management team will be appointed to manage suitable sub-contractors for the removal of the installation. Perenco standard procedures for operational control and hazard identification and management will be used. Where possible the work will be coordinated with other decommissioning operations in the SNS. Perenco will monitor and track the process of consents and the consultations required as part of this process. Any changes in detail to the offshore removal programme will be discussed with DECC.

6.2 Post-Decommissioning Debris Clearance and Verification

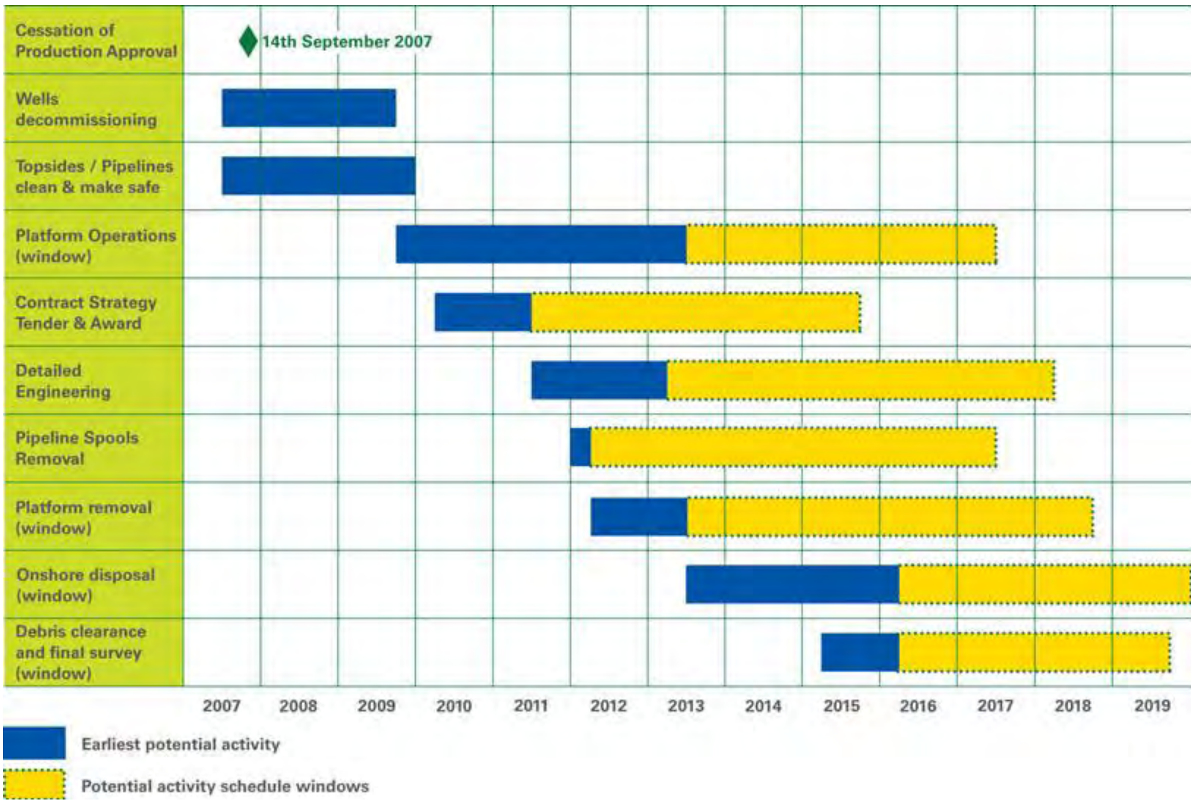
Include a statement similar to the example in blue below. ***(Suggested maximum of 100 words)***

A post decommissioning site survey will be carried out around 500m radius of installation sites and 200m corridor along each existing pipeline route. Significant seabed debris will be recovered for onshore disposal or recycling in line with existing disposal methods. Independent verification of seabed state will be obtained by trawling the platform area. This will be followed by a statement of clearance to all relevant governmental departments and non- governmental organisations.

6.3 Schedule

Project Plan: *Insert a Gantt chart version of the simplified project plan, with key dates and defined milestones, as per example below.*

Figure 6.1: Gantt Chart of Project Plan



6.4 Costs

An overall cost estimate (example format shown in table below) should be provided to DECC, following UK Oil and Gas Guidelines on Decommissioning Cost Estimation. Updated estimates must be provided in confidence to DECC at the 'define' stage as appropriate.

Table 6.1 – Provisional Decommissioning Programme(s) costs	
Item	**Estimated Cost (£m)**
Platform(s) /Jacket(s) - Preparation / Removal and Disposal	Provide to DECC
Pipeline(s) Decommissioning	Provide to DECC
Subsea Installation(s) and Stabilisation Feature(s)	Provide to DECC
Well Abandonment	Provide to DECC
Continuing Liability – Future Pipeline and Environmental Survey Requirements	Provide to DECC
TOTAL	Provide to DECC

6.5 Close Out

Include a statement similar to the example in blue below. ***(Suggested maximum of 100 words)***

In accordance with the DECC Guidelines, a close out report will be submitted to DECC explaining any variations from the Decommissioning Programme(s) (normally within 4 months of the completion of the offshore decommissioning scope) including debris removal and independent verification of seabed clearance and the first post-decommissioning environmental survey.

6.6 Post-Decommissioning Monitoring and Evaluation

Provide a statement, similar to the example in blue below, which details your proposed monitoring and evaluation programme. ***(Suggested maximum of 100 words)***

A post decommissioning environmental seabed survey, centred around sites of the wellheads and installation, will be carried out. The survey will focus on chemical and physical disturbances of the decommissioning and compared with the pre decommissioning survey. Results of this survey will be available once the work is complete, with a copy forwarded to DECC. All pipeline routes and structure sites will be the subject of surveys when decommissioning activity has concluded. After the surveys have been sent to DECC and reviewed, a post monitoring survey regime will be agreed by both parties, typically one (or more) post decommissioning environmental surveys and structural pipeline surveys.

7 SUPPORTING DOCUMENTS

Provide a list of supporting documents (and supporting diagrams, graphics or other material) that you have referenced in the programme(s) which are not presented in the Appendices. See examples in blue below.

Table 7.1: Supporting Documents	
Document Number	*Title*
1	*Environmental Statement*
2	*Comparative Assessment*

For latest document versions provide a web link for all stakeholder/interested parties (or access to other document control mechanism).

8 PARTNER LETTER(S) OF SUPPORT

Copies of letter(s) of support from current equity holders in the field should be provided here. Originals should be submitted with final version of the Programme(s).

APPENDIX B

Abandonment Programme Release Formal Assessment Process

Guidance Notes

Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroleum Act 1998

Produced by

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INTRODUCTION

The decommissioning of offshore oil and gas installations and pipelines on the United Kingdom Continental Shelf (UKCS) is controlled through the Petroleum Act 1998, as amended by the Energy Act 2008.

The UK's international obligations on decommissioning are governed principally by the 1992 Convention for the Protection of the Marine Environment of the North East Atlantic (OSPAR Convention). Agreement on the regime to be applied to the decommissioning of offshore installations in the Convention area was reached at a meeting of the OSPAR Commission in July 1998.

The responsibility for ensuring that the requirements of the Petroleum Act 1998 are complied with rests with the Department of Energy and Climate Change (DECC). DECC is the competent authority on decommissioning in the UK for OSPAR purposes.

The aim of these notes, which have been prepared by DECCS's Offshore Decommissioning Unit in Aberdeen, in consultation with other Government Departments, is to provide guidance to those engaged in preparing programmes for the decommissioning of offshore installations and pipelines. Account has been taken of views expressed by operating companies and other interested parties.

These guidance notes, which were first issued in August 2000, provide a framework and are not intended to be prescriptive. They will be reviewed regularly and updated as necessary. We intend to make the process of submission and approval of a decommissioning programme as flexible as possible within statutory and policy constraints, allowing adequate time for full and considered consultation but without unnecessary delay. We recognise that circumstances will vary from case to case and that differing approaches may be required.

Furthermore, whilst these guidance notes are intended to provide fairly detailed guidance to those engaged in preparing decommissioning programmes, they should not be read in isolation from the relevant legislation.

March 2011

1. GOVERNMENT POLICY AND THE UK'S INTERNATIONAL OBLIGATIONS

Policy

1.1 Government will seek to achieve effective and balanced decommissioning solutions, which are consistent with international obligations and have a proper regard for safety, the environment, other legitimate uses of the sea, economic considerations and social considerations. Our policies and practices on decommissioning will recognise the need to:

- maximise energy production as a contribution to UK energy security, and
- take impacts on climate change into account.

1.2 DECC will seek to ensure that:

- interested parties have a clear view of the policy and the procedures;
- decisions on decommissioning proposals are based on full information, are taken in an efficient manner and place as little administrative burden as possible on the various parties concerned;
- decommissioning decisions are consistent with waste hierarchy principles and are taken in the light of full and open consultations;
- decommissioning will be regarded as the last option after re-use of the facilities for energy or other projects has been ruled out;
- disposal decisions in respect of installations that are candidates for derogation from OSPAR Decision 98/3 are judged against the criteria and approach set out in Annex A to this guidance.
- comparative assessments of decommissioning options take account of impacts on climate change;
- forums exist for the sharing of information, experience gained and lessons learned.

International Obligations

1.3 The UK's international obligations on the decommissioning of offshore installations have their origins in the United Nations Convention on the Law of the Sea of 1982. The Convention entered into force in 1994 and the UK acceded to it in 1997. Article 60(3) includes the following:

"Any installations or structures which are abandoned or disused shall be removed to ensure safety of navigation, taking into account any generally accepted international standards established in this regard by the competent international organisation. Such removal shall also have due regard to fishing, the protection of the marine environment and the rights and duties of other States. Appropriate

publicity shall be given to the depth, position and dimensions of any installations or structures not entirely removed".

1.4 The competent international organisation for this purpose is the International Maritime Organisation which in 1989 adopted the IMO Guidelines and Standards setting out the minimum global standards for the removal of offshore installations.

1.5 In 1992 a new convention, the Convention on the Protection of the Marine Environment of the North East Atlantic ("the OSPAR Convention"), was agreed. This regional convention, which applies to specific sea areas of the North East Atlantic, including the North Sea and parts of the Arctic Ocean, replaced and updated the 1972 Oslo Convention on the Protection of the Marine Environment by Dumping from Ships and Aircraft and the 1974 Paris Convention on the Prevention of Marine Pollution from Land-Based Sources. The OSPAR Convention came into force on 25 March 1998.

1.6 In July 1998 at the First Ministerial meeting of the OSPAR Commission, a new regime for the decommissioning of disused offshore installations was established under the new Convention. Ministers adopted a binding Decision (*OSPAR Decision 98/3 - reproduced at Annex B*) to ban the disposal of offshore installations at sea.

1.7 Pipelines are not covered by OSPAR Decision 98/3. There are no international guidelines on the decommissioning of disused pipelines. Section 10 describes UK policy.

The Main Features of OSPAR Decision 98/3

1.8 Under the terms of Decision 98/3, which entered into force on 9 February 1999, there is a prohibition on the dumping and leaving wholly or partly in place of offshore installations. The topsides of all installations must be returned to shore. All installations with a jacket weight less than 10,000 tonnes must be completely removed for re-use, recycling or final disposal on land.

1.9 The Decision recognises that there may be difficulty in removing the 'footings' of large steel jackets weighing more than 10,000 tonnes and in removing concrete installations. As a result there is a facility for derogation from the main rule for such installations. It has been agreed that these cases should be considered individually to see whether it may be appropriate to leave the footings of large steel installations or concrete structures in place. Nevertheless, there is a presumption that they will all be removed entirely and exceptions to that rule will be granted only if the assessment and consultation procedure, which forms part of the OSPAR Decision, shows that there are significant reasons why an alternative disposal option is preferable to re-use or recycling or final disposal on land.

1.10 The derogation provision for the footings of large steel installations applies only to those installed before 9 February 1999. All steel installations placed in the maritime area after that date must be totally removed. It should also be noted that the Ministerial 'Sintra' statement which accompanied Decision 98/3 made clear that new concrete installations would be used only when it is strictly necessary for safety or technical reasons.

1.11 The Decision provides for review by the OSPAR Commission at regular intervals, to consider in the light of experience and technical developments whether the derogations from the general ban on dumping continue to be appropriate. The most recent review, conducted in 2008, concluded that the limited operational experience to date of decommissioning concrete substructures and footings of large steel installations is insufficient to justify changing the derogation criteria. Nevertheless, there is a clear intent within the Decision to reduce the scope of possible derogations and it can be expected that future derogation cases presented to OSPAR will be judged against the advances in technology or contractor capabilities that may have been achieved at the time. A further review of the Decision will be undertaken in 2013.

2. LEGISLATION

Description of the Legislation

2.1 Before the owners of an offshore installation or pipeline can proceed with its decommissioning they must obtain approval of a decommissioning programme under the Petroleum Act 1998. It should be noted that although the Petroleum Act 1998 refers to an 'abandonment programme' the preferred and generally accepted term is a 'decommissioning programme'.

2.2 Under the 1998 Act a decommissioning programme should contain an estimate of the cost of the measures proposed; specify the times at or within which those measures are to be taken or make provision for determining those times; and, where an installation or pipeline is to remain in position or be only partly removed, include provision for maintenance where necessary. It is recognised that where appropriate a decommissioning programme will deal with both removal and disposal of an installation or pipeline. The contents of a decommissioning programme are set out more fully *in Section 6 of and Annex C to this guidance*.

2.3 In addition to approval of a decommissioning programme, the following will also need to be obtained as appropriate:

- confirmation that the requirements of the Coast Protection Act 1949, Section 34, Part II have been satisfied;
- acceptance of a Dismantlement Safety Case under the Offshore Installations (Safety Case) Regulations 2005 (installations only);
- fulfilment of notification requirements to Health and Safety Executive (HSE) under regulation 22 of the Pipeline Safety Regulations 1996;
- any environmental consents or permits required during decommissioning activity;
- approvals for the shipment of waste; and
- approval of a well abandonment programme in accordance with the obligation contained in the petroleum production licence.

2.4 It is recognised that certain preparatory works which do not prejudice decommissioning options should be able to be carried out before approval of a decommissioning programme e.g. removal of some equipment and cleaning. Details will be discussed with the Operator in each case.

2.5 If a decommissioning programme includes any new deposits in the sea, for example, of rock gravel or grout bags, a licence may be required under Part II of the Food and Environment Protection Act 1985.

2.6 The disposal of materials onshore must comply with the relevant health, safety, pollution prevention and waste requirements, including in particular Parts I and II of the Environmental Protection Act 1990.

2.7 In certain circumstances additional authorisation under the Radioactive Substances Act 1993 may be necessary.

2.8 It is the responsibility of the Operator or contractor, as appropriate, to obtain the necessary approvals and authorisations.

2.9 Annex D describes in outline the legislation other than the Petroleum Act 1998 which applies to decommissioning and the Government body responsible for its administration. This includes a list of the main consents and authorisations that are likely to be required in addition to the approval of a decommissioning programme. (*See also Annex E*). The environmental regulations that apply to offshore decommissioning activity are set out in *Section 12.*

Petroleum Act 1998

2.10 The principal legislation is the Petroleum Act 1998 (the 1998 Act) which is administered by DECC.

2.11 Part IV of the 1998 Act provides a framework for the orderly decommissioning of disused installations and pipelines on the UKCS.

2.12 The principal provisions of Part IV of the 1998 Act:

- enable the Secretary of State, by written notice, to require the submission of a costed decommissioning programme for each offshore installation and submarine pipeline. Those persons given notices are jointly liable to submit a programme;
- where a decommissioning programme is approved by the Secretary of State, make it the (joint and several) duty of the persons who submitted it to secure that it is carried out;
- provide the Secretary of State with means to satisfy himself that any person who has a duty to secure that an approved decommissioning programme is carried out will be capable of discharging that duty and, where he is not so satisfied, require that person, by notice, to take such action as may be specified;
- in the event of failure by those given notice to submit a programme or secure that it is carried out, enable the Secretary of State to do the work and recover the cost from those given notice;
- provide penalties for failure to comply with notices; and
- enable the Secretary of State to make regulations relating to decommissioning.

Charging a fee for approving and revising offshore decommissioning programmes.

2.13 It is a fundamental principle of the decommissioning regime that a person who is responsible for developing or operating an offshore installation/pipeline should also be responsible for decommissioning at the end of its useful life. The Department therefore intends to charge Industry a fee for approving and revising offshore (oil and gas) decommissioning programmes rather than passing the costs onto the taxpayer which is in line with the 'polluter pays' principle of environmental law.

2.14 Section 29 of the 1998 Act allows the Department to charge a fee in respect of its expenditure under Part 4 of the 1998 Act when a person submits an abandonment programme. The Secretary of State also has a power to charge a fee in respect of a proposal to revise an abandonment programme (section 34(4)).

2.15 The charging mechanism will allow the Department to recover its expenditure for the exercise of its functions under Part 4 of the Act 1998. The Department will not be seeking to make a profit from such a charge but merely recover its costs in carrying out those functions.

2.16 The Department will shortly be undertaking a twelve-week consultation to seek views of relevant stakeholders on the proposals to charge a fee in respect of offshore (oil and gas) installations and pipelines decommissioning programmes. Subject to the outcome of this consultation and the Parliamentary process, when Regulations are made to implement the proposals set out in the consultation document, the Department will update the Guidance Notes further to reflect this.

Energy Act 2008: Oil and Gas Decommissioning

2.17 Chapter 3 of Part 3 of the Energy Act 2008 ("the 2008 Act") amends Part IV of the Petroleum Act 1998. The 1998 Act consolidated provisions from the Petroleum Act 1987. Since the regime was originally established in 1987 there have been changes in business practices in the oil and gas industry, such as increased participation by smaller companies which have fewer assets and as such bring increased risks that they might not be able to meet their decommissioning liabilities. Moreover, experience has shown that it has not always been possible to share liabilities equitably between parties responsible for any installation or pipeline.

2.18 The detailed oil and gas provisions of the 2008 Act are discussed in *section 3*. In summary, the 2008 Act amends the regime by:

- Enabling the Secretary of State to make all the relevant parties liable for the decommissioning of an installation or pipeline and, where a licence covers multiple sub-areas, clarifying which licensees will be liable.

- Giving the Secretary of State power to require decommissioning security at any time during the life of an oil or gas field if the risks to the taxpayer are assessed as unacceptable.

- Protecting the funds put aside for decommissioning, so in the event of insolvency of the relevant party, the funds remain available to pay for decommissioning and the taxpayers' exposure is minimised.

Energy Act 2008: Gas Storage and Import Infrastructure and Carbon Capture and Storage

2.19 Gas production from the UKCS is declining and it is expected that the UK will be reliant on imported gas to meet well over half of demand by 2020. Without sufficient and timely new storage and import infrastructure, there will be increased risks of a tight gas supply demand balance in the UK in the future. Companies have already responded to declining UK gas production by investing in new gas storage and import infrastructure. However, additional investment will be needed as production declines and companies investing in the UK have sought a clear and stable regulatory framework.

2.20 Prior to the 2008 Act, the UK's offshore legislative regime was primarily designed for licensing oil and gas production. Chapter 2 of Part 1 of the 2008 Act creates a new regulatory framework specifically designed for offshore gas storage and Liquefied Natural Gas (LNG) unloading projects. In addition, paragraphs 10 and 11 of Schedule 1 amend the definition of the parties that can be required to submit a decommissioning programme and the definition of an offshore installation specified in Part IV of the 1998 Act. This ensures the decommissioning of offshore gas storage and importation infrastructure can be governed by the provisions in the 1998 Act.

2.21 Carbon Capture and Storage (CCS) is a process involving the capture of carbon dioxide from the burning of fossil fuels and its transportation and storage in secure spaces, such as geological formations, including under the seabed. CCS can be applied to a range of industrial processes including coal-fired and gas-fired electricity generation. It has the potential to reduce carbon dioxide emissions by up to 90% of standard coal-fired generation. The Government is committed to the development of CCS with electricity generation. Most of the activities involved are standard industrial processes and can be regulated by established legislation. However, permanent storage of carbon dioxide is a novel activity, and pre 2008 legislation to control depositions below the surface of the land and seabed is not well suited to licensing the storage of carbon dioxide. Chapter 3 of Part 1 of the 2008 Act establishes a framework for the licensing of carbon dioxide storage and enforcement of the licence provisions. It also applies existing offshore legislation, including the decommissioning provisions of Part IV of the 1998 Act, to offshore structures used for this purpose (see section 30 of the 2008 Act). It is recognised that as CCS is a novel activity it may prove necessary over time as experience is gained to modify Part IV of the 1998 Act and section 30 also enables regulations to be made modifying the provisions of Part IV in relation to CCS.

2.22 The decommissioning provisions of Part IV of the 1998 Act therefore apply to offshore facilities established for the purposes of gas storage, LNG unloading projects and CCS. The framework for decommissioning outlined in these guidance notes is therefore relevant to such projects and will be updated to reflect this as experience is gained. However, it should be noted that although the provisions of chapter 3 of the 2008 Act will apply to the territorial sea adjacent to Scotland (0 to 12 nautical miles), Scottish Ministers have the relevant legislative, licensing and enforcement powers for CCS projects in this area. The functions of Part IV of the 1998 Act will be exercised by the Scottish Ministers in the case of carbon dioxide storage installations licensed by them. Correspondence regarding the decommissioning of CCS infrastructure in the territorial sea adjacent to Scotland should therefore be addressed to the Scottish Government.

3. DECOMMISSIONING OBLIGATIONS UNDER THE PETROLEUM ACT 1998

The Process

3.1 Section 29 of the 1998 Act enables the Secretary of State to serve notices requiring the recipient to submit a costed decommissioning programme for his approval at such time as he may direct. The programme (referred to in the 1998 Act as an "abandonment programme") should contain the measures the notice holder(s) propose to take in connection with the decommissioning of the installation(s) or pipeline(s) listed. The 1998 Act consolidated Parts I and II of the Petroleum Act 1987 with various other petroleum enactments. Notices previously served under section 1 of the 1987 Act will continue to be valid. Amendments made to the 1998 Act by the Energy Act 2008 are incorporated in the following paragraphs and detailed later within this section.

3.2 For installations, notices may be served not only on the licensees but also on the company that manages the installation (we expect this to be the Operator, see paragraph 3.15), the owners of the installation and the parties to a Joint Operating Agreement (JOA) or similar agreement. In the first instance, notices will be served on all the companies in these categories. However, notices under section 29 may also be served on parents or other associates. The option of serving more widely will be pursued only in cases where it is judged that satisfactory arrangements, including financial, have not or will not be made to ensure a satisfactory decommissioning programme is carried out.

3.3 The administrative process is started when a field development is approved and construction of the installation has commenced. If it has not been included as part of the field development plan, at this stage DECC will send a Facility Information Request (FIR) to the person with management responsibility for the field (the Operator). This asks the Operator to confirm the accuracy of information relating to installations, pipelines and companies involved in the field.

3.4 Once the FIR has been returned, DECC will send the company that operates the installation, the owners and the relevant licensees and JOA parties a 'warning letter'. This communication warns the recipient that the Secretary of State is considering issuing him a notice under section 29 of the 1998 Act and provides him with the opportunity to make written representations if he considers that he should not be given such a notice. The recipients are given up to 30 days in which to make representations although this period may be shorter for a fast track development. Following this, subject to any representations received, a 'section 29 notice' is issued to each of the parties.

3.5 Relevant licensees and JOA parties will be those that are entitled to derive a financial or other benefit from the installation. The benefit must arise as a result of using the installation for purposes for which it is, or will be, established or maintained (see paragraph 3.23, multiple sub-area bullet point, for further details).

3.6 The serving of a notice for pipelines follows the same procedure as for installations. In most cases, notices are issued only to the owners of a pipeline. However, notices may also be served on parents or other associates where we have concerns about the arrangements to ensure satisfactory decommissioning. For pipelines, notice serving procedures are instigated when the pipeline works authorisation is given and construction has commenced.

3.7 By this process the obligation to submit a decommissioning programme on or before such date as the Secretary of State may subsequently specify, is placed upon each of the appropriate companies. The notice also advises of the requirement to carry out consultations with specific parties, including fishermen's organisations and other interested bodies (*see Annex H*), when preparing a programme. A list of the organisations to be consulted will be sent to each of the notice holders nearer the time of decommissioning.

3.8 The time between serving an initial section 29 notice and the point at which the Secretary of State calls for a decommissioning programme may be considerable. We expect to call for a programme towards the end of the life of the field and the facilities. However, in certain circumstances, for example the early shut down of the field, the Secretary of State may call for the programme at an earlier stage.

3.9 All section 29 notice holders, whether or not they have sold their interest in a field, are treated equally in law and will be required to agree the decommissioning programme. The obligation to carry out the approved decommissioning programme is joint and several. This is an important concept which means that if any one of those with a duty to carry out a programme is unable to do so, the other interested parties will be responsible for the defaulting party’s burden. Ultimately, this could result in one party being liable for the full decommissioning costs. As a consequence the Department would therefore expect to be notified in the event of a company dissolution. In practice, the Operator is expected to lead on the preparation and implementation of the programme.

3.10 Once the decommissioning obligation has been fixed by means of the section 29 notice, it remains so unless it is withdrawn by the Secretary of State. If a company disposes of its interest in the installation(s) or pipeline(s) on a field, the Secretary of State will consider whether to exercise his discretion under section 31(5) to withdraw the notice (*see Section 4 and Annex F for information taken into account when considering withdrawal*). The other companies who have received notices for that installation or pipeline will be sent a letter advising them of the proposed withdrawal and will be given up to 30 days in which to make written representations although this period may be shorter to meet the timescale of the deal.

3.11 If a notice is withdrawn this does not necessarily mean that the company will have no decommissioning responsibilities in relation to the equipment. In accordance with section 34 of the 1998 Act, a company may, in certain circumstances and following the approval of a programme, be placed under a duty to carry out that programme even though it has previously been released from a notice under section 31(5). Section 34 also enables the Secretary of State to do the same with any person on whom notices could have been served since the serving of the first section 29 notice. This situation has not occurred to date and we regard it as a measure of last resort. In the first instance, the Secretary of State would expect the current section 29 notice holders to carry out the decommissioning and would only use the powers in section 34 in potential default cases which we endeavour to avoid by the use of prudent security arrangements. If such action was necessary in respect of more than one company we would aim to agree a fair and reasonable distribution of the liabilities in discussion with the companies concerned. This might be related to the revenues earned by the various companies during their involvement in the field and DECC would want to consider the companies' proposals for dealing with the situation.

3.12 At the same time as the Secretary of State considers whether to withdraw the notice from an exiting party, if the incoming company is not already in receipt of a section 29 notice, DECC will instigate the notice serving process outlined in paragraph 3.4. A 'warning letter' will be sent to the new company, which, subject to any representation, will be followed by a section 29 notice. At this stage it is not necessary to precede the warning with a FIR as the relevant information will be retained from the original FIR sent around the time of field approval.

3.13 Where a section 29 notice is not withdrawn the notice holder would not be liable for any new installations emplaced in the field after the assignment of their interest. However they would be liable for any new equipment added to an installation already covered by their existing notice.

3.14 If a company has concerns relating to a specific section 29 case they should contact DECC's Offshore Decommissioning Unit for further clarification.

Manager of an Installation

3.15 The increasing use of contractors taking on the day-to-day management of an installation has led to queries regarding whether or not the contractor would receive a section 29 notice as the manager of the installation falling within section 30(1)(a) of the 1998 Act. The wording of section 30(1)(a) indicates only one person can manage the installation and our interpretation is that the Operator approved by the Secretary of State under the Petroleum Act licence would be the manager. We do not treat contractors providing a service to the Operator as a manager within section 30(1) (a) of the Act. Companies are welcome to ask if a particular contractual situation might create liabilities.

3.16 DECC has been asked if the Operator of the host installation would become the manager of a tieback if the tieback Operator defaulted. It was clear that the host platform Operator had no authority to make strategic managerial decisions regarding the tieback field and no entitlement to the tieback's production. We consider that a benefit must arise from the exploitation or exploration of mineral resources or storage or recovery of gas for which the tieback installation is, or will be, established or maintained. This will not include the host Operator if they are only receiving a tariff for transporting production from the tieback via the host installation (see paragraph 3.23, multiple sub-area bullet point, for further details). DECC took the view that the host Operator would not be regarded as the manager of the tieback installation.

Definition of an Installation – Tiebacks

3.17 The increasing use of tiebacks to host platforms raises the question whether the tieback should be treated as a separate installation for the purposes of Part IV of the 1998 Act. Where the tieback is separate, under the 1998 Act (as amended by the 2008 Act), only licensees and JOA parties that benefit from the oil or gas production from the field for which the tieback installation was built, or is maintained, will be served with a notice under section 29 for that installation. If the tieback is considered part of the host installation it is not possible to separate the liability from the host.

3.18 Although a tieback depends on the host installation to transport (and sometimes process) the production, we do not believe this automatically makes the tieback part of the host installation. Many tiebacks could switch to another host platform if it offered a better deal justifying building a new link. In addition, very few installations on the UKCS are truly independent. Most share pipelines to get their production ashore and many share processing, accommodation or control facilities.

3.19 We consider the following parameters in determining when it is reasonable and proportionate to treat tiebacks as separate installations:

1. Whether a tieback exploits a different field to that used by the host installation.

2. Whether a tieback has a structure on the seabed or on a jacket which comprises at least one wellhead producing oil or gas, probably a protection structure and possibly a manifold connecting pipelines.

3. Whether a tieback is on a different licence to the field exploited by the host installation.

4. Whether there are different licence groups for the tieback and host.

3.20 Whether the tieback will be treated separately will be determined on the facts of the case and where it exploits a separate field and there is a new structure on the seabed (parameters 1 and 2), it is anticipated it will be treated as a separate installation. If these factors do not apply, there would need to be another strong reason to justify regarding the tieback as separate. Where a tieback is part of the host installation, it is for the companies concerned to decide whether and how to apportion the costs of decommissioning as the legislation is silent on this point.

3.21 An extended reach well is not considered to be a separate installation. Although the field may be geologically separate from that exploited by the host, the well is drilled from the host platform and is connected back to the host for production; there is no separate seabed or surface facility to treat as an installation.

Energy Act 2008 Amendments

3.22 Chapter 3 of Part 3 of the 2008 Act amends Part IV of the 1998 Act. The relevant oil and gas provisions are detailed below.

Section 72: Persons who may be required to submit abandonment programmes

3.23 This section of the 2008 Act makes amendments to section 30 of the 1998 Act to extend the range of persons who may be given a notice under section 29, and who may therefore be required to submit a decommissioning programme.

- **Licence Holders:** Subsection (2)(a) inserts a new paragraph into section 30(1) of the 1998 Act. This extends the regime to include licensees who have transferred an interest in a licence to another party without the prior approval of the Secretary of State. Licences may not be transferred from one company to another without DECC's consent. Unconsented transfers are nevertheless effective. DECC is not aware of cases where unconsented transfers have been made with fraudulent or criminal intent. However, there have been a number of cases where unconsented transfers appear to have happened because of carelessness by the companies involved. For example, where DECC has consented to a transfer to one subsidiary and then the transfer is altered so that the transfer is actually made to a different subsidiary, without getting a revised DECC consent.

- **Limited Liability Partnerships:** Subsections (2)(b) and (3) amend paragraphs (1)(e) and (2)(c) of section 30 of the 1998 Act to substitute references to "company" with "body corporate". In addition, subsection (5) substitutes five new subsections for section 30(8) of the 1998 Act and subsection (6) amends section 30(9) of the Act. These provisions set out the test for determining whether, for the purpose of section 30, one company is associated with another. The effect of the amendments and the new subsections is to substitute references to "company" with "body corporate" and to provide the test for whether one body corporate is associated with another. The purpose of these provisions is to bring limited liability partnerships within the scope of the association provisions of section 30 and, therefore, treat them as persons which may be served with a section 29 notice.

- **Timing of Notice Serving:** Subsection (4) amends subsection (5)(b) of section 30 of the 1998 Act. Subsection (5)(b) provides that a person who may be required to submit a programme includes a person who is already carrying on certain activities (such as exploitation of mineral resources) on an offshore installation. The amendment extends these provisions so that they also apply to persons who intend to carry on such activities in the future. This enables licensees and parties to joint operating or similar agreements to be served with a notice at the same time as the person who manages the installation e.g. before production begins.

- **Multiple Sub-Area/Multiblock Licences:** Petroleum exploration and extraction licences issued under either the 1998 Act or the Petroleum (Production) Act 1934 tend to be divided by the licensees at a commercial/contractual level into separate sub-areas. As a result, some of the licensees may have no commercial interest in a particular sub-area, and therefore no interest in an installation in that sub-area. Paragraphs (b) and (c) of section 30(1) of the 1998 Act give the Secretary of State the power to make all licensees and parties to joint operating or similar agreements jointly and severally liable for decommissioning every installation in the licensed area regardless of whether they benefit or have the potential to benefit from the particular installation. Subsection (7) inserts four new subsections into section 31 of the 1998 Act preventing the Secretary of State from serving a decommissioning obligation on licensees and parties to joint operating (or similar) agreements if they have never been entitled to derive a relevant financial or other benefit from the installation in question.

As a result of the new subsection (A1) of section 31, if a person has never been entitled to derive any benefit, whether financial or other, from the installation, the Secretary of State will no longer be able to serve a notice under section 29 to that person if they fall within paragraphs (b) or (c) of section 30(1) and have never been within paragraphs (a), (ba) – see first bullet point above, (d) or (e). Subsections (B1) and (C1) specify that a relevant financial or other benefit will not arise as a result of using the installation for purposes other than those for which it is, or is to be, established or maintained. In addition by virtue of subsection (D1) of section 31, a person that is within paragraph (e) of section 30(1) by virtue of his association to a person exempted by the new provision will be similarly exempt.

Subsection (8) of section 72 of the Energy Act 2008 extends the above provisions to section 34 of the 1998 Act. Section 34 specifies the persons that may be given a duty to carry out an existing approved programme. As a result of the new subsection it is not possible to propose that a licensee or a party to a joint operating (or similar) agreement should be added as a party to the programme if that person has never been entitled to derive any benefit from the installation covered by the programme and has never been within paragraphs (a), (ba) – see first bullet point above, (d) or (e) of section 30(1).

The benefit referenced in the above paragraphs must arise from the exploitation or exploration of mineral resources or storage or recovery of gas from the field for which the installation was built or is maintained. The intention is to capture benefits which are the substantive equivalent of an ownership or equity interest in the field and installation e.g. by receiving production or payments, royalties or bonuses in lieu of production. By contrast, a person would not be treated as benefitting from activities on an installation simply by virtue of (a) either providing or receiving inter-field services under a standard transportation, processing and operating agreement (b) buying oil or gas production from the installation (c) trading carbon dioxide allowances or (d) supplying goods or services to the installation.

Section 73: Financial resources etc

3.24 This section of the 2008 Act clarifies the information which may be required to satisfy the Secretary of State of a person's ability to fund its decommissioning obligations, or potential obligations. It also makes provision to bring forward the time when the Secretary of State may require a person to take relevant action (such as providing financial security, for example a letter of credit), in order to reduce the financial risk to the taxpayer.

- **Information Gathering, Prior to Serving Notice Under 29 or Imposing Decommissioning Obligation:** Subsection (2) substitutes three new subsections for subsection (1) of section 38 of the 1998 Act. Section 38 sets out that the Secretary of State can, by issuing a notice, require specified financial information and documents (for example up to date management accounts) in relation to a decommissioning programme. It also creates an offence for non-compliance with the notice and for knowingly providing false information. The purpose of the amendments is to widen the circumstances in which the Secretary of State may give such a notice to determine whether he wishes to impose a decommissioning obligation on a person by serving a notice under section 29 or by adding that person to an existing approved programme (and making them subject to the obligations within that programme).

- **Information Gathering, After Serving Notice Under Section 29 or Imposing Decommissioning Obligation:** Subsections (3) and (4) make amendments to subsection (2) of section 38 of the 1998 Act and insert a new subsection (2A). This provision allows the Secretary of State to require more specific information which could include: a detailed estimate of the costs of decommissioning; predictions of future revenue; the costs and benefits of any plans for further development; or up to date management accounts.

  Under the 1998 Act the provision for such information could not be required prior to the approval of a programme. This amendment allows such information to be required from persons who have been served with a notice under section 29, in addition to those under a duty to carry out a decommissioning programme. This enables the Secretary of State to assess whether to require financial security.

- **Require Action, Including Establishing Financial Security:** Subsection (5) substitutes new subsections (4) and (4A) for section 38(4) of the 1998 Act. These enable the Secretary of State, after consulting the Treasury, to require action (including the provision of financial security, such as a letter of credit) to be taken by a person who has been served with a notice under section 29 or who has a duty to carry out a programme, where the Secretary of State is not satisfied that the person is capable of carrying out the programme. Previously the Secretary of State only had the ability to require such action following the approval of a decommissioning programme. By enabling the Secretary of State to require action once a notice under section 29 has been served, but in advance of programme approval, the taxpayer can be protected against the early failure of a development. Prior to issuing a notice requiring the establishment of security the recipient will be given the opportunity to make representations regarding whether they should be given such a notice. Annex F details the risk assessment process used to determine when such mitigation measures may be necessary.

- **Offence to Disclose Information:** Subsection (6) makes it an offence to disclose information obtained under section 38(1) or (2) of the 1998 Act without the consent of the person who provided it, unless the disclosure is required for the purposes of the exercise of the Secretary of State's functions under the Act or another piece of legislation. Section 40 of the 1998 Act sets out the penalties that apply if an offence is committed under subsection (6). This ensures the ongoing confidentiality of any cost or financial data submitted.

Section 74: Protection of abandonment funds from creditors

3.25 This section inserts two new sections into the 1998 Act after section 38, to protect funds set aside for the purposes of decommissioning in the event of insolvency.

- **New section 38A: Protection of funds set aside for the purposes of abandonment programme.** This section is designed to ensure that, in the event of the insolvency of a person responsible for a decommissioning programme or a person with obligations under that programme, the funds set aside for meeting those liabilities remain available for decommissioning and are not available to the general body of creditors. The protection in the event of insolvency applies where any funds have been set aside in a secure way (such as a trust or other arrangement which was established on or after 1 December 2007) for meeting obligations under a programme. This provision applies whether the security is established before or after the programme's approval, as long as it is clear in the arrangement that it has been established to secure the obligations under the programme.

  Subsection (4) provides that the term "security" has a wider interpretation for the purpose of funds which will be protected from creditors in the event of insolvency. The list, which is non-exhaustive, provides examples of the interpretation of security. Without such a definition, a court could take a more restricted legal view. This in turn could mean that an instrument that was intended to be used to meet some or all of the decommissioning costs could be accessed by creditors in the event of the operator's insolvency.

To enable protection of the funds, subsection (6) specifically disapplies any provision of the Insolvency Act 1986, the Insolvency (Northern Ireland) Order 1989 or any other enactment or rule of law the operation of which would prevent or restrict the security being used for the purpose for which it was set up (meeting decommissioning liabilities). Subsection 7 extends the meaning of "enactment" to include Acts of the Scottish Parliament.

- **New section 38B: Directions to provide information about protected assets.** This section is intended to ensure that creditors and potential future creditors of a person responsible for a decommissioning programme are aware of any decommissioning funds affected by the new powers to disapply insolvency legislation. The publication of information regarding relevant security arrangements will enable informed decisions to be made by creditors and potential future creditors. Subsections (1) and (2) therefore set out that the Secretary of State may give a direction to a person responsible for a programme to publish details of the fund or other arrangements at the time and in the manner specified by the Secretary of State (for example in the financial pages of that person's website). Subsection (3) enables the Secretary of State or a creditor of the person responsible for the decommissioning programme to apply for a court order to ensure compliance with a direction.

Section 107 and Schedule 5: Minor and consequential amendments

3.26 Paragraphs 9 and 10(b) of Schedule 5 amend section 31(1) and section 34(3) of the 1998 Act. Subsection (1) of section 31 provides that the Secretary of State may not give notice under section 29 to certain persons specified in section 30(1) if the Secretary of State has been and continues to be satisfied that adequate arrangements (including financial) have been made by other persons so specified. Similarly, section 34(3) provides that the Secretary of State shall not propose that certain persons specified in section 30(1) shall be given a duty to secure that an approved programme is carried out unless it appears to him that one of the current parties has or may default. The effect of the new provisions is to provide that these limitations will no longer apply to persons specified in paragraph (d) of section 30(1) (a person who owns any interest in an installation otherwise than as security for a loan). There is increasing use of floating production systems where the ownership may change during the life of the field, and this amendment takes account of this change in practice, and enables the decommissioning risk to be spread to new owners with an interest in an installation.

3.27 Paragraph 10(a) of Schedule 5 extends the class of persons that can be given a duty to carry out an approved programme to include licensees who have transferred an interest in the licence to another party without the prior approval of the Secretary of State. This is in line with section 72 subsection (2)(a) outlined above.

3.28 Paragraph 11 of Schedule 5 inserts text into section 45 of the 1998 Act (Interpretation of Part IV) so that the definition of "submarine pipeline" includes a pipeline which is intended to be established. This enables notices under section 29 to be served for submarine pipelines prior to installation, mirroring the existing requirements for offshore installations.

4. CHANGES OF OWNERSHIP AND FINANCIAL SECURITY AGREEMENTS

4.1 In recent years there has been a significant and increasing number of UKCS licence assignments from large companies to smaller ones. The introduction of innovative Licensing schemes such as 'Frontier' and especially 'Promote' licences has brought a number of new companies to the UKCS. Ministers have agreed that such activity on the UKCS should be encouraged and that there should be a free trade in mature offshore oil and gas assets so as to extend field life and maximise economic recovery. At the same time the Government has a duty to ensure that the taxpayer is not exposed to an unacceptable risk of default in meeting the costs associated with decommissioning. To enable these two goals to be achieved, the Government has developed a policy to ensure that adequate security for decommissioning costs is maintained on a field by field basis. *The details of this policy, including the circumstances in which decommissioning security may be appropriate, are set out in Annexes F and G.*

5. PLANNING FOR DECOMMISSIONING

The Decommissioning Programme Process

5.1 The consideration and approval of decommissioning programmes for installations and pipelines will be co-ordinated by DECC's Offshore Decommissioning Unit in Aberdeen. The Unit will consult with the other Government Departments, Devolved Administrations and Agencies who have an interest in the consideration of decommissioning proposals. There may, however, be occasions when DECC will ask the Operator to make direct contact with a particular Government Department, for example, with the Department for Environment, Food and Rural Affairs or its agency, the Centre for Environment, Fisheries and Aquaculture Science on an aspect which may have specific implications for fisheries.

5.2 It is clear that our international obligations will result in the great majority of installations being returned to shore for re-use or recycling or final disposal on land. However, experience to date has shown that the circumstances surrounding individual cases will vary. For example, it may be appropriate for topsides or jackets to be re-used offshore without being returned to land; in such a case, proper consideration would need to be given to cleaning and to any waste which may arise. The technical, environmental, safety and economic issues will need to be considered carefully in each instance. The whole process leading to approval of a decommissioning programme is intended to be flexible, transparent and subject to public consultation.

5.3 The process involved in a typical case where the installation is being completely removed for re-use or recycling or final disposal on land can be illustrated as follows:

Decommissioning Programme Process - Main Stages

Stage 1	Stage 2	Stage 3	Stage 4	Stage 5
Preliminary discussions with DECC	Detailed discussions and submission of consultation draft programme to DECC, other interested parties and the public for consideration	Formal submission of a programme and approval under the Petroleum Act	Commence main works and undertake site surveys	Monitoring of site

5.4 Consideration of those cases involving concrete installations or large steel installations with a jacket weight greater than 10,000 tonnes will follow a similar process. However, in these cases it is expected that it will be necessary to undertake more extensive public consultations on the proposals. Operators will wish to discuss the details and the timing of such a 'dialogue' with DECC but there is likely to be benefit in initiating the process at an early stage, certainly at Stage 1 and possibly earlier. If discussion at Stage 1 suggests there is a case for seeking a derogation from the general rule of OSPAR Decision 98/3, a detailed assessment in accordance with the procedures set out in the Decision will have to be carried out at Stage 2. In deciding whether a case has been made out for a derogation DECC will judge the assessment against the criteria set out in *Annex A.*

5.5 Consultations with the OSPAR Contracting Parties would be initiated by the Government at Stage 2. The more extensive consultations referred to above are likely to continue throughout Stages 1 and 2.

5.6 A flowchart setting out how the consideration of decommissioning proposals will operate in practice is at *Annex J*.

Stage 1

5.7 Early discussions between the Operator and DECC's Offshore Decommissioning Unit will ensure that timely action is being taken by the Operator and that the decommissioning process is well understood. The Offshore Decommissioning Unit will involve other Government Departments as necessary.

5.8 Discussions should commence well ahead of forecast cessation of operations. In the case of a large field with multiple facilities, this may be 3 years or more in advance. In the case of a potential derogation case it may be up to 5 years in advance. The onus rests with the Operator to initiate these discussions. At the same time the Offshore Decommissioning Unit will endeavour to maintain a more general dialogue with operators on their future UKCS plans in order to understand the likely timing of cessation of production from their fields and the implications for decommissioning of the infrastructure.

5.9 The Offshore Decommissioning Unit will advise of any particular factors or requirements that need to be taken into account in the light of circumstances existing at that time. Where appropriate DECC will encourage operators to co-operate with the view to a joint and integrated approach. DECC will also promote the sharing of technical information and experiences amongst operators (*see Section 17)*.

5.10 The Operator will be asked to outline the likely timetable of future events to form a basis for agreement on when more detailed discussions should commence and what documentation should be prepared in advance.

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Stage 2

5.11 This stage involves more detailed discussion of an Operator's decommissioning proposals and the consideration by Government and other interested parties of a consultation draft of the decommissioning programme.

5.12 With the more straightforward cases there may be little distinction in practice between Stages 1 and 2 with the need for only one or two meetings before the consultation programme can be submitted for Government consideration. Drafting and consideration of those cases involving concrete installations or large steel installations with a jacket weight greater than 10,000 tonnes may be more complex. If an Operator seeks a derogation from the general rule of re-use, recycling or final disposal on land, the application will have to be considered in accordance with the assessment procedures set out in Annex 2 to OSPAR Decision 98/3.

5.13 Transparency and openness is an important aspect of any decommissioning decision. At the same time as submitting the programme for Government consideration, the Operator will be required to carry out consultations with interested parties. The extent of these consultations will be determined by the particular circumstances of the case. In all cases the Operator will be asked to undertake statutory consultations as provided for under section 29(3) of the Petroleum Act 1998. *The consultation process is described more fully in Section 6 of this guidance*. If consultations with other OSPAR Contracting Parties are necessary the process will be initiated at this stage by Government in accordance with the procedures set out in Annex 3 to OSPAR Decision 98/3.

Stage 3

5.14 Following the completion of consultations it should be possible for the Operator and the Offshore Decommissioning Unit to agree a final version of the programme. When this has been achieved the Secretary of State will call formally for submission of the programme under the 1998 Act.

Stage 4

5.15 This stage covers the implementation of the approved decommissioning programme up to the completion of site surveys. The programme will specify the arrangements by which DECC will be kept informed of progress and, where appropriate, will indicate the 'milestones' at which progress will be reviewed. Any revisions to the programme will be subject to the Secretary of State's approval in accordance with the provisions of section 34 of the 1998 Act.

5.16 At the conclusion of Stage 4 the Operator will be required to satisfy DECC that the approved programme has been implemented. This will normally involve the submission of a Close-out Report within four months of the completion of offshore work, including debris clearance and post-decommissioning surveys. *(See Section 13 for further details).*

Stage 5

5.17 The final stage will require the Operator to implement arrangements for monitoring, maintenance and management of the decommissioned site and any remains of installations or pipelines that may exist. The scope and duration of the monitoring requirements will be agreed between the Operator and DECC in consultation with other Government Departments and details will be included in the decommissioning programme. *(See also Sections 14 to 16 of this guidance).*

Deferral and Phased Decommissioning

5.18 The Government aims to ensure the orderly decommissioning of offshore infrastructure in a timely and efficient manner, in line with the UK's international obligations and domestic legislation. DECC's expectation is that the removal of redundant installations, including subsea equipment, will be carried out as soon as reasonably practicable. At the same time we recognise that disused facilities including pipelines may represent important UKCS infrastructure and provide the means for the further development of hydrocarbon reserves, the storage of carbon dioxide or hydrocarbon gas. Where a specific opportunity has been identified deferral of decommissioning can be considered. The timing of decommissioning will also be influenced by market factors and vessel availability and there may be benefits from coordinating offshore work with other projects being undertaken in a similar timescale. This may involve agreeing that decommissioning work can be conducted during a window of opportunity, possibly spread across two or three seasons. In general, though, in view of the UK's obligations under OSPAR, DECC expects the removal of disused installations not to be delayed unless a robust case demonstrates there is a specific reuse opportunity or other justifiable reasons for deferring decommissioning.

5.19 If it is proposed that final decommissioning of an installation be deferred to a later date, DECC should be consulted well in advance and a sustainable case will need to be made. In most instances it should be possible to agree the deferral by an exchange of correspondence. If it is agreed that decommissioning may be delayed until a more appropriate time, DECC will issue a formal letter setting out the conditions upon which it is prepared to defer, until a specified date, the issue of a direction to submit a decommissioning programme.

5.20 However, in most cases it is expected that a decommissioning programme will be required at the outset, particularly if the proposal relates to the phased decommissioning of an installation or of a number of installations in a field which may involve the removal of topsides and other equipment in advance of the jacket. Such phasing may be appropriate in order to take advantage of possible savings through synergy and advances in new technology *(see Section17).* In these circumstances a programme would need to address the overall strategy for decommissioning the installation or installations, although it may be accepted that an Operator should seek agreement initially for the first activity only, e.g. removal of topsides.

5.21 Amongst the factors to be taken into account in considering the case for deferral or phasing and the extent of any prior works will be the condition of the installation, the presence of any hazards including potentially polluting substances and the need for accurate information about the nature and location of any such substances. DECC and HSE will wish to be satisfied that the integrity of the installation will be maintained or that any deterioration will not be such as to present unacceptable risks before or compromise the execution of decommissioning operations.

5.22 The Operator will need to make arrangements to ensure installations which are to be left in place are suitably marked and lit (*see Section 15*).

5.23 In the case of pipelines, DECC should be consulted in the same way as for installations *(see Section 10)*.

Median Line Facilities

5.24 Treaties relating to median line fields contain provisions requiring consultation between the relevant Governments on decommissioning proposals. DECC will take the lead in these discussions and will consult the Operator. If facilities are located on both sides of the median line it is likely that decommissioning proposals will be developed through joint discussions with the relevant Governments, leading to the submission of a single programme for approval by both Governments under their respective legislative regimes.

Role of Other Government Departments

5.25 As already indicated, consultation with Government Departments and the Devolved Administrations at an early stage in the decommissioning process will be essential. DECC will act as the focal point for discussions with operators but other Government Departments, Devolved Administrations and Agencies will be fully involved in the process and will represent their own particular interests as appropriate at these discussions. As part of this process it may be necessary in some cases for operators to enter into a separate dialogue with other Departments if specific matters relating to their areas of responsibility arise. The outcome of any separate discussions will be fed back into the overall assessment of the decommissioning proposals.

5.26 It will also be the Operator's responsibility to obtain as appropriate, or ensure the existence of, any necessary consents or authorisations arising from legislation administered by other parts of DECC, other Government Departments, Devolved Administrations or Agencies. Statutory consultation may be an essential part of the authorisation processes and applications should be made in good time. *Further details of the role and responsibilities of other Departments are set out in Annex E; see also Section 6 of this guidance and Annex D.*

6. DECOMMISSIONING PROGRAMMES

Content ***(see also Annex C)***

6.1 In most cases the general rule under OSPAR Decision 98/3 will apply and the decommissioning programme will provide for full removal for re-use, recycling or final disposal of the installation on land. In preparing the decommissioning programme in these cases there will be no need for a detailed comparative assessment of the options nor will there be a need for the Government to consult the OSPAR Contracting Parties. It will, however, be important to make the draft programme available for public comment and to include in the programme a statement indicating how the principles of the waste hierarchy will be met and to show the extent to which the installation, including the topsides and the materials contained within the installation, will be re-used, recycled or disposed of on land.

6.2 The waste hierarchy is a conceptual framework which ranks the options for dealing with waste in terms of their sustainability, beginning with reducing the generation of waste. Failing that, re-use either for the same or a different purpose should be considered ahead of recovering value from the waste through recycling. Only if none of these offers an acceptable solution should disposal be considered. The Government reiterates its support for the waste hierarchy in the national waste strategies for Scotland, England and Wales, published by the Scottish Environment Protection Agency (http://www.sepa.org.uk/) and the Department of Environment, Food and Rural Affairs (http://www.defra.gov.uk/).

6.3 The OSPAR Decision recognises that, in line with the waste hierarchy, the re-use of an installation is first in the order of preferred decommissioning options. DECC is keen to encourage the re-use of facilities wherever this is practical and will expect the decommissioning programme to demonstrate that the potential for re-use has been examined fully.

6.4 It will be essential to support the chosen decommissioning option with an Environmental Impact Assessment. This should form part of the decommissioning programme and should assess the impact of the project on the environment and climate change, which is of increasing importance in the decision making process. This should include information on the energy balance and emissions of the options considered. It should also include the impacts of any explosives likely to be deployed subsea during decommissioning activity. It should also take account of requirements under the EU Habitats Directive. *(See Annex C, Item 10).*

6.5 In the more complex cases relating to concrete installations and to steel installations with a jacket weight greater than 10,000 tonnes a full assessment of the options in accordance with Annex 2 to OSPAR Decision 98/3 must be undertaken by the Operator so that DECC may judge whether there is a case for seeking a derogation from the general rule of the Decision. The assessment will include the practical availability and potential impacts of alternative options in order to allow an authoritative comparative evaluation to be carried out. The assessment will form part of the decommissioning programme. *The approach to* *this assessment and an indication of the criteria that may be applied is set out in Annex A to these guidance notes.*

6.6 A decommissioning programme should identify all items of equipment and materials that have been installed (e.g. installations, subsea equipment, wells, pipelines) or have accumulated (e.g. drill cuttings) at the site. In addition, with the exception of items left downhole, the programme should clearly specify any equipment or remains to be decommissioned in place.

6.7 A programme may deal with the decommissioning of all of the facilities located on a field or part of the facilities including a single installation or pipeline. The precise content of a programme may vary according to the circumstances. However, the following sections are likely to be necessary in most cases. *Details of the information to be provided under each section are set out in Annex C*.

1. Introduction
2. Executive Summary
3. Background information
4. Description of Items to be decommissioned
5. Inventory of materials
6. Removal and disposal options
7. Selected removal and disposal option
8. Wells
9. Drill Cuttings
10. Environmental Impact Assessment
11. Interested party consultations
12. Costs
13. Schedule
14. Project management and verification
15. Debris clearance
16. Pre- and Post-decommissioning monitoring and maintenance
17. Supporting studies

6.8 If the above format is not appropriate in any particular case a modified version should be agreed in discussion with DECC.

6.9 Where particular items of equipment or facilities on a field are to be decommissioned together but are the subject of different sets of section 29 notices (i.e. the groups of notice holders for the facilities are not all composed of the same companies), it is important that it is possible to distinguish clearly from the decommissioning programme with whom the decommissioning obligations rest and what those obligations are. The effect of the Petroleum Act 1998 is to require there to be a decommissioning programme in respect of each set of equipment which is the subject of a section 29 notice or series of related section 29 notices. This means that, although it may be possible to present different programmes within a single document, it must be done in such a way as to allow the different programmes to be identified in order to isolate the liabilities of the different groups of notice holders.

6.10 Decommissioning proposals for pipelines should be prepared in a separate programme although, as indicated above, this may be presented within the overall decommissioning document. *Section 10 outlines the general approach to pipeline decommissioning and Annex C explains how to structure combined decommissioning documents*.

6.11 Draft Decommissioning Programmes must include a statement about costs. However, we realise that accurate cost data and confirmation of the final decommissioning option may be dependent on the outcome of a commercial tendering process. Operators should discuss any sensitivities with DECC.

Submission

6.12 At a mutually agreed time, following preliminary discussions, the Operator should submit to DECC 26 copies of a consultation draft of the decommissioning programme. Exact requirements will be discussed with the Operator before submission. Copies of the draft programme will be distributed by DECC to other Government Departments and Agencies. Submission in CD ROM form is the preferred method, although some paper copies will also be required. Six copies will be required when the holders of section 29 notices are directed formally to submit the decommissioning programme.

6.13 The documents should be marked for the attention of the Head of the Offshore Decommissioning Unit and addressed to:

The Department of Energy and Climate Change
Atholl House
86–88 Guild Street
ABERDEEN AB11 6AR

6.14 On receipt of a draft decommissioning programme the Offshore Decommissioning Unit will circulate it for consideration by others with an interest within DECC and to other Government Departments. The latter will comprise: The Scottish Government (both the Environmental Quality Directorate and Marine Scotland); the Department of Environment, Food and Rural Affairs; the Ministry of Defence including the UK Hydrographic Office and HM Revenue & Customs. The Health and Safety Executive; the Crown Estate and the Joint Nature Conservation Committee (or the appropriate Conservation Committee) will also receive a copy of all programmes. The Scottish Environment Protection Agency will receive a copy if the facilities are in waters adjacent to Scotland; the Environment Agency if in waters adjacent to England or Wales and the Department of the Environment for Northern Ireland if in waters adjacent to Northern Ireland. *The roles of these other Government Departments and Agencies are set out in Annex E.* Draft programmes are also circulated to Historic Scotland and the Royal Commission on the Ancient and Historical Monuments of Scotland (RCAHMS). *Section 19 explains the role of these bodies.*

6.15 At the same time DECC will agree with the Operator a timetable for considering the draft programme and submitting it for approval by the Secretary of State. DECC will use its best endeavours to complete the consideration of the draft decommissioning programme within 10 weeks.

6.16 In that period DECC's Offshore Decommissioning Unit will co-ordinate all Government comments on the draft and submit a written response to the Operator. Further meetings may be necessary at this stage to discuss whether additional information and amendments to the draft programme may be necessary.

6.17 At the same time as submitting the draft decommissioning programme to DECC the Operator should also release it to the statutory consultees and announce the proposals in the Press and on the Internet.

6.18 The outcome of the consultation process should be reviewed with DECC and details included in the final version of the programme submitted for the Secretary of State's approval.

6.19 Where appropriate, consideration of the draft decommissioning programme will run in parallel with:

- consideration by DECC Licensing and Consent Unit Field Teams of any Cessation of Production (COP) Document (the procedures for submitting an application for COP are set out in DECC's 'Guidance Notes on Procedures for Regulating Offshore Oil and Gas Field Developments' which can be viewed on DECC's Oil & Gas Website at https://www.og.decc.gov.uk/regulation/guidance/index.htm

- consideration by the HSE of the Dismantlement Safety Case

- consideration of any environmental permits or consents, and

- any onshore disposal consents or licences which may be necessary, including any transfrontier shipment of waste issues.

6.20 It is important that sufficient time is allowed for the proper consideration of the proposals in a decommissioning programme. In the majority of cases only one draft of the decommissioning programme will be necessary. However, in those cases involving installations that are candidates for derogation under OSPAR Decision 98/3 it is likely that more than one draft will be required.

Derogation cases

6.21 For derogation cases, DECC will still aim to comment on the consultation draft of the decommissioning programme within 10 weeks. However, given the complexities of a derogation case this process may take longer to complete. At the same time as submitting the draft to DECC the Operator should commence statutory consultations and announce the proposals in the Press and on the Internet. The outcome of these consultations should be reviewed with DECC and details included in a post consultation draft of the decommissioning programme along with any comments received from DECC in response to the Government consideration of the draft.

6.22 Having received the updated draft of the decommissioning programme DECC should be satisfied that there are sufficient grounds to initiate consultations with other OSPAR Contracting Parties on the intention to issue a permit allowing derogation from the terms of OSPAR Decision 98/3 *(see paragraph 6.27)*.

6.23 When submitting the decommissioning programme for approval, the outcome of the OSPAR process should be reflected in the document.

Consultations

6.24 At the point at which the draft decommissioning programme is submitted to DECC, the Operator should commence statutory consultations as required under section 29(3) of the Petroleum Act 1998. These consultations will be with the representatives of those parties who may be affected by the decommissioning proposals, such as the fishing industry. Details of the statutory consultees will be specified in a letter to all companies in receipt of a notice under section 29 of the Act. *A list of the parties normally included is at Annex H.* The Statutory Consultees should normally be given 30 days in which to comment.

6.25 The Operator will also be asked to announce its proposals by placing a public notice in appropriate national and local newspapers and journals and to place details on the Internet. This notice should indicate where copies of the draft decommissioning programme can be viewed and to whom representations should be submitted. A standard form of notice including appropriate publications can be provided by DECC. Hard copies of the draft programme should be made available for inspection at the Operator's offices and a copy can be placed on the Internet. At the same time DECC will indicate on its website that the programme has been issued for consultation.

6.26 The results of consultations should be reported in the decommissioning programme when it is submitted for approval. This can be best achieved by appending to the programme the correspondence with interested parties and by indicating the extent to which their views have been taken into account.

6.27 In the more complex cases which require assessment in accordance with the procedures set out in OSPAR Decision 98/3, operators will need to develop and manage a wide-ranging public consultation process. The form and timing of this process should be discussed with DECC. As a guide, such a process may take up to 12 months and should commence at an early stage. Oil & Gas UK has developed Guidelines on Stakeholder Engagement for Decommissioning Activities. These can be viewed at http://www.oilandgasuk.co.uk/

6.28 If these Stakeholder consultations lead to a decision to seek a derogation under the OSPAR Decision it will be necessary for DECC to consult the other

OSPAR Contracting Parties. Annex 3 to the Decision sets out the required consultation process that may take up to 8 months to complete.

6.29 DECC will be responsible for submitting the case for derogation to the OSPAR Secretariat but the Operator will be asked to prepare a document that supports this case. The contents of this derogation document should be discussed with DECC. It should be based on the draft decommissioning programme but should only contain those factors that are relevant to the derogation case. Preparation of the derogation document would normally commence at the time of submission of the post statutory consultation draft of the decommissioning programme. Sufficient copies will be required for distribution to all of the OSPAR Contracting Parties.

Approval

6.30 At the appropriate time, normally when the draft decommissioning programme has been finalised, the Secretary of State will formally direct, in writing, the holders of section 29 notices, in respect of the installations and/or pipelines, to submit a decommissioning programme for his approval. In response to the direction, the Operator, on behalf of the notice holders, should submit six copies of the decommissioning programme based on the agreed draft. The decommissioning programme should include a letter from each current equity holder with a section 29 notice signifying that it is being submitted by the Operator on their behalf. A letter of support will not be required from a non equity holder who has sold their interest but retains a section 29 notice. Each of the notice holders will be informed by written notice when the Secretary of State has approved the programme. If the approval is to be subject to specific conditions, the notice holders will be given the opportunity to make representations. A link to the approved programme will be included on DECC's website.

Reporting Progress

6.31 There should be a commitment within the programme for the Operator to keep DECC informed of progress during the decommissioning activities and submit a Close-out report within four months of the completion of offshore work, including debris clearance and post-decommissioning surveys. The report should outline how the decommissioning programme was carried out. Details of the information to be provided in the report are set out in *Section 13.*

6.32 The progress of a decommissioning programme from submission of the draft through to approval will be indicated on DECC's Oil & Gas website http://www.og.decc.gov.uk/upstream/decommissioning/programmes/index.htm.

Changes to Approved Programmes

6.33 When a decommissioning programme has been approved it is the duty of each of the persons who submitted it to secure that it is carried out and that any conditions to which the approval is subject are complied with. Those who submitted the programme may, if they wish, propose alterations to it. If changes are contemplated, the Operator, on behalf of the persons who submitted the programme, should discuss them with DECC. Section 34 of the 1998 Act sets out the provisions that apply to the revision of an approved decommissioning programme.

7. THE IMPACT OF OSPAR DECISION 98/3

General

7.1 The purpose of this chapter is to provide guidance on the decommissioning requirements which apply, in accordance with the requirements of the OSPAR Decision 98/3, to the various types of installation located on the UKCS.

7.2 Under the OSPAR Decision, which has been accepted by the UK Government, the disposal at sea and the leaving wholly or partly in place of disused offshore installations is prohibited. There is a presumption in favour of re-use, recycling or final disposal on land.

7.3 The Decision recognises that there may be difficulty in removing the 'footings' of large steel jackets weighing more than 10,000 tonnes and in removing concrete installations. As a result there are exceptions from the general rule for these categories of installation. However, it should be noted that any steel installation emplaced after 9 February 1999, the date on which the Decision entered into force, must be completely removed for re-use or recycling or final disposal on land.

7.4 The following table indicates the options which may be considered for various categories of offshore installations located on the UKCS:

Installation (excluding topsides)	**Weight (tonnes)**	**Complete Removal to land**	**Partial Removal to land**	**Leave wholly in place**	**Re-use**	**Disposal at Sea**
Fixed Steel	<10,000	Yes	No	No	Yes (3)	No
Fixed Steel	>10,000	Yes	Yes (1)(2)	No	Yes(3)	No
Concrete - gravity	Any	Yes	Yes(2)	Yes	Yes	Yes(4)
Floating	Any	Yes	No	No	Yes	No
Subsea	Any	Yes	No	No	Yes	No

Notes:

(1) Only the 'footings' or part of the 'footings' may be left in place.

(2) Minimum water clearance of 55 metres required above any partially removed installation which does not project above the surface of the sea.

(3) The placement of materials on the seabed for a purpose other than that for which it was originally intended is covered by the OSPAR Guidelines on Artificial Reefs in relation to Living Marine Resources of June 1999 (*OSPAR Reference: Agreement 1999-13. Available from the OSPAR website at* www.ospar.org).

(4) Although the disposal of the substructure of a concrete installation at a deep-water site is an option this must be considered against

the UK Government announcements at the time of the Decision when Ministers stated that there would be no toppling and no local or remote dumping of offshore installations.

7.5 In addition, the OSPAR Decision recognises that in very exceptional and unforeseen circumstances resulting from structural damage or deterioration or equivalent difficulties there may be a case for any offshore installation to be dumped or left wholly or partly in place.

7.6 The following provides further guidance:

Topsides

7.7 The topsides of all installations must be returned to shore for re-use or recycling or final disposal on land. Under the Decision topsides are defined as those parts of an entire offshore installation which are not part of the substructure and includes modular support frames and decks where their removal would not endanger the structural stability of the substructure.

Steel Installations weighing less than 10,000 tonnes (excluding topsides)

7.8 All steel installations weighing less than 10,000 tonnes must be completely removed for re-use or recycling or final disposal on land. The Decision defines a steel installation as being a disused offshore installation which is constructed wholly or mainly of steel.

7.9 Any piles should be severed below the natural seabed level at such a depth to ensure that any remains are unlikely to become uncovered. The depth will in the main depend upon the prevailing seabed conditions and currents.

Steel Installations weighing more than 10,000 tonnes (excluding topsides)

7.10 There is a presumption that steel installations weighing more than 10,000 tonnes should be totally removed and this is the starting point for the consideration of any decommissioning proposals. However, it is possible to consider whether it is appropriate for the 'footings' or part of the 'footings' of the installation to be left in place. The upper section of the jacket above the 'footings' or any removed part of the 'footings' must either be re-used, recycled or disposed of on land. Any removed parts may not be disposed of at sea.

7.11 The Decision defines the 'footings' as those parts of a steel installation which are below the highest point of the piles which connect the installation to the sea bed or, in the case of an installation constructed without piling, form the foundation of the installation and contain amounts of cement grouting similar to those found in piled installations. The definition also includes those parts of a steel installation which are so closely connected to the 'footings' as to present major engineering problems in severing them. In some situations this will allow subsea templates which are located within the area of the ‘footings’ and made inaccessible by the ‘footings’ to be included in this definition.

7.12 If the owners of the installation wish the Government to consider seeking a derogation (paragraph 3 of the Decision) from the general rule of total removal, it will be necessary for the Operator of the installation to demonstrate that there are significant reasons why leaving the 'footings' or part of the 'footings' in place is preferable to returning them to shore for re-use or recycling or final disposal on land. To achieve this, an assessment must be carried out by the Operator in accordance with Annex 2 to the Decision. Such an assessment will not need to cover options which are not available in this case (e.g. deep-sea disposal or toppling). This assessment may be judged against the criteria and approach set out in Annex A to this guidance. If the Government is satisfied that a case has been made it will undertake consultations with the other OSPAR Contracting Parties through the OSPAR Secretariat in accordance with Annex 3 to the Decision.

Gravity Based Concrete Installations

7.13 Decision 98/3 recognises that the decommissioning of concrete installations is likely to present particular problems. For the purposes of the Decision a concrete installation is defined as being a disused offshore installation constructed wholly or mainly of concrete.

7.14 As with all other installations the topsides of concrete installations must be returned to shore for re-use, recycling or disposal. However, it is possible to consider whether the remainder of the installation, or part of it, should remain in place or be disposed of at a deep-water licensed site. If the owners of a concrete installation wish the Government to consider a derogation from the general rule of total removal to land, the Operator must undertake an assessment in accordance with Annex 2 to the Decision. The assessment must show that there are significant reasons why sea disposal or leaving the installation in place is preferable to re-use or recycling or final disposal on land. This assessment may be judged against the criteria and approach set out in Annex A to this guidance. If the Government is satisfied that a case has been made it will carry out consultation with the other OSPAR Contracting Parties in accordance with Annex 3 to the Decision.

Hybrid Installations

7.15 Since the introduction of Decision 98/3 a number of new development proposals have considered the use of hybrid installations, combining both concrete and steel in their construction. A typical hybrid installation may have a concrete gravity base storage tank with a fixed steel structure located above.

7.16 For the purposes of the OSPAR Decision and the requirements of the Petroleum Act 1998 such installations will be classified as being either steel or concrete on the basis of the definitions set out in the Decision, i.e. that it is either, constructed wholly or mainly of steel or it is constructed wholly or mainly of concrete. This is not simply a matter of weight and account will be taken of the purposes for which the different parts of the structure will be used.

7.17 If such an installation is classified as concrete then account will have to be taken of the Ministerial 'Sintra' statement which accompanied the Decision and made clear that new concrete installations would be used only when it is strictly necessary for safety or technical reasons. In such circumstances a case justifying the use of concrete would have to be made as part of the Field Development Plan (FDP) approval process and would need to demonstrate that the installation can be removed for re-use, recycling or final disposal on land at the time of decommissioning. This is in accordance with the IMO requirement that any installation emplaced on or after 1 January 1998 must be designed and constructed so that entire removal would be feasible *(see Section 8).*

Floating Installations

7.18 Floating installations will include Floating Production Facilities (FPFs) or Floating Production Systems (FPSs), Floating Production, Storage and Off-take vessels (FPSOs), Floating Storage Units (FSUs), and Single Buoy Mooring facilities (SBMs). At the end of field life such installations will be floated off location and re-use elsewhere as a production or storage facility is likely to be a high priority. In those cases where re-use does not prove possible it will be necessary to return the facility to shore for storage or dismantling in line with the hierarchy of waste disposal options.

7.19 It is recognised that there may be a requirement to remove floating production facilities from a field in advance of the approval of a decommissioning programme. In these circumstances removal of the facility can be agreed through an exchange of correspondence between the Operator and DECC. Details of the removal would be included retrospectively in the decommissioning programme. Further guidance can be provided by DECC.

7.20 Most floating installations will have associated sub-sea equipment. The approach to decommissioning sub-sea installations is dealt with in the following paragraphs.

Sub-sea Installations

7.21 Sub-sea installations are not separately identified in the Decision but fall within the definition of a steel installation or a concrete installation. Sub-sea installations include drilling templates, production manifolds, well heads, protective structures, anchor blocks and anchor points, anchor chains, risers and riser bases. Subject to paragraph 7.22 below, such installations must be completely removed for re-use or recycling or final disposal on land. Any piles should be cut below natural seabed level at such a depth to ensure that any remains are unlikely to become uncovered. The depth will in the main depend upon the prevailing seabed conditions and currents. However, any application to leave in place a sub-sea installation because of the difficulty of removing it would need to be made in terms of satisfying the requirements of paragraph 3(c) (exceptional and unforeseen circumstances) of the Decision.

7.22 The exception to the general rule above relates to any part of an offshore installation which is located below the surface of the sea-bed or any concrete anchor-base associated with a floating installation which does not, and is not likely to, result in interference with other legitimate uses of the sea. These are not included in the definition of a disused steel or concrete installation in the Decision and as such may be left in place. However, any concrete anchor-base which results, or is likely to result, in interference with other legitimate uses of the sea can remain in place as a derogation from the main rule only if an assessment under Annex 2 to the Decision, and consultation in accordance with Annex 3, show that to be preferable to re-use or recycling or final disposal on land.

Exceptional Circumstances

7.23 In exceptional and unforeseen circumstances any disused offshore installation may be disposed of at sea or left wholly or partly in place as a derogation from the main rule if it can be demonstrated that, due to structural damage or deterioration, or some other cause presenting equivalent difficulties, there are significant reasons why such disposal is preferable to re-use or recycling or final disposal on land. An assessment in accordance with Annex 2 to the Decision would have to be carried out along with consultation under Annex 3. This derogation is likely to apply only in very exceptional cases where for significant environmental, technical or safety reasons an installation, or part of it, cannot be removed. Again, the assessment could be judged against the criteria and approach set out in Annex A to this guidance.

8. IMO GUIDELINES AND STANDARDS FOR THE REMOVAL OF OFFSHORE INSTALLATIONS AND STRUCTURES

8.1 The International Maritime Organisation Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone, adopted by IMO Assembly on 19 October 1989, (Resolution A.672 (16)), set out the minimum global standards to be applied to the removal of offshore installations and structures.

8.2 The Guidelines and Standards, which were designed essentially to ensure the safety of navigation, make clear that they are not intended to preclude a coastal state from imposing more stringent removal requirements for existing or future installations or structures on its continental shelf or in its exclusive economic zone.

8.3 The UK Government's acceptance of OSPAR Decision 98/3 means that the UK will apply the provisions of that instrument when considering the decommissioning of offshore installations rather than the standards and guidelines laid down by the IMO. However, certain aspects of the IMO Guidelines and Standards will still be relevant:

- Any disused installation or structure, or part thereof, which projects above the surface of the sea should be adequately maintained.
- An unobstructed water column of at least 55 metres must be provided above the remains of any partially removed installation to ensure safety of navigation.
- The position, surveyed depth and dimensions of any installation not entirely removed should be indicated on nautical charts and any remains, where necessary, properly marked with aids to navigation.
- The person responsible for maintaining any aids to navigation and for monitoring the condition of any remaining material should be identified.
- The liability for meeting any claims for damages which may arise in the future should be clear.
- On or after 1 January 1998, no installation or structure should be placed on any continental shelf or in any exclusive economic zone unless the design and construction of the installation or structure is such that entire removal upon abandonment or permanent disuse would be feasible.

8.4 Most of these requirements are reflected in Annex 4 to the OSPAR Decision which sets out the terms and conditions which must be specified in any permit issued by a Contracting Party for disposal at sea.

8.5 Our requirements on the marking of any remains of an installation are set out in *Section 15 of this guidance.*

9. TREATING, KEEPING AND DISPOSING OF WASTE

9.1 The Environment Agency (in England and Wales) and the Scottish Environment Protection Agency (in Scotland) are responsible for administering and enforcing the waste management controls. Anyone who deposits, recovers or disposes of waste must do so in compliance with the conditions of a waste management licence, or within the terms of an exemption from licensing, and in a way which does not cause pollution of the environment or harm to human health.

9.2 Movements of waste from the UKCS to other Member States and Non-Member States are deemed to be a transboundary movement and therefore subject to transfrontier regulations. Unless wastes are exempt from the scope of Council Regulation No 1013/2006/EC, the "Waste Shipment Regulation" (WSR) and the UK Management Plan for the Export and Import of Wastes, any movements for disposal would be prohibited. While wastes generated by the normal operation of oil platforms may be exempt from the scope of the WSR, decommissioned installations are not. Any transboundary shipment for recovery operations, which is not exempt from the scope of WSR, could be classified as a shipment of unlisted waste. Unlisted waste shipments require prior written notification to, and the written consent of, the competent authorities involved in the shipment. Given the highly specialised nature of waste shipment controls, operators planning to carry out any decommissioning or an associated activity involving waste generated on offshore platforms should contact the relevant Agency. Council Directive 2006/117/Euratum, transposed by the Transfrontier Shipment of Radioactive Waste and Spent Fuel Regulations 2008, excludes NORM wastes and the shipment of disused sources to authorised storage facilities. Therefore transfer of such material does not require authorisation under transfrontier shipment of radioactive waste. Further details are available in the international shipments of waste guidance. These can be viewed at: http://www.environment-agency.gov.uk/business/sectors/32447.aspx *(Details of the waste management licensing system, and other relevant legislation, are contained in Annex D).*

10. PIPELINE DECOMMISSIONING

General Approach

10.1. The Petroleum Act 1998 provides a framework for the orderly decommissioning of both offshore installations and offshore pipelines. The Pipeline Safety Regulations 1996, administered by the HSE, provide requirements for the safe decommissioning of pipelines. This chapter provides guidance on the approach to the decommissioning of pipelines on the UKCS. The provisions of OSPAR Decision 98/3 do not apply to pipelines. There are no international guidelines on the decommissioning of disused pipelines. Decommissioning proposals for pipelines should be contained within a separate programme from that for installations. However, programmes for both pipelines and installations in the same field may be submitted in one document.

10.2 The following approach will be taken in considering the decommissioning of pipelines on the UKCS:

- decisions will be taken in the light of individual circumstances;
- the potential for reuse of the pipeline in connection with further hydrocarbon developments should be considered before decommissioning together with other existing projects (such as hydrocarbon storage and carbon capture and storage). If reuse is considered viable, suitable and sufficient maintenance of the pipeline must be detailed.
- all feasible decommissioning options should be considered and a comparative assessment made (*the factors to be taken into account are included in Annex C*);
- any removal or partial removal of a pipeline should be performed in such a way as to cause no significant adverse effects upon the marine environment;
- any decision that a pipeline may be left in place should have regard to the likely deterioration of the material involved and its present and possible future effect on the marine environment.
- account should be taken of other uses of the sea.

10.3 Where it is proposed that a pipeline should be decommissioned in place, either wholly or in part, then the decommissioning programme should be supported by a suitable study which addresses the degree of past and likely future burial/exposure of the pipeline and any potential effect on the marine environment and other uses of the sea. The study should include the survey history of the line with appropriate data to confirm the current status of the line including the extent and depth of burial, trenching, spanning and exposure.

10.4 Determination of any potential effect on the marine environment at the time of decommissioning should be based upon scientific evidence. The factors to be taken into account should include the effect on water quality and geological and hydrographic characteristics; the presence of endangered, threatened or protected species; existing habitat types; local fishery resources; and the potential for pollution or contamination of the site by residual products from, or deterioration of, the pipeline. In order to consider the potential environmental impact it is necessary to evidence the contents of the line and outline the cleaning operations that will be undertaken. In addition to cleaning hydrocarbons reasonable endeavours to remove wax and other contaminants, particularly where a line is to be decommissioned in place, will be expected. Experience to date highlights the advantage of commencing cleaning operations early in the decommissioning process. Guidance on cleaning topsides and pipelines prior to decommissioning has been developed through the Pilot Brownfields Initiative. This is available from the Oil & Gas UK website:

http://www.oilandgasuk.co.uk/cmsfiles/modules/publications/pdfs/OP057.pdf

10.5 Because of the widely different circumstances of each case, it is not possible to predict with any certainty what may be approved in respect of any class of pipeline. Each will be considered on its merits and in the light of a comparative assessment of the alternative options. This policy also applies to pipeline bundles which are already in place on the seabed. The Department would however expect that any new pipeline bundles which are currently under construction should be designed for future removal.

Leaving in place

10.6 As a general guide the following pipelines (inclusive of any "piggyback" lines and umbilicals that cannot easily be separated) may be candidates for in-situ decommissioning:

- those which are adequately buried or trenched and which are not subject to development of spans and are expected to remain so;

- those which were not buried or trenched at installation but which are expected to self bury over a sufficient length within a reasonable time and remain so buried;

- those where burial or trenching of the exposed sections is undertaken to a sufficient depth and it is expected to be permanent;

- those which are not trenched or buried but which nevertheless are candidates for leaving in place if the comparative assessment shows that to be the preferred option (e.g. trunk lines);

- those where exceptional and unforeseen circumstances due to structural damage or deterioration or other cause means they cannot be recovered safely and efficiently.

10.7 Judgements regarding the degree of burial or trenching necessary will be undertaken on a case by case basis in the light of individual circumstances. We will wish to be satisfied that the pipeline is sufficiently buried or trenched below seabed level to avoid obstruction to other uses of the sea. Decisions on the appropriate depth of burial or trenching will take account of seabed conditions and other relevant factors but it is expected that burial or trenching to a minimum depth of 0.6 metres above the top of the pipeline will be necessary in most cases.

Removal

10.8 Small diameter pipelines, including flexible flowlines and umbilicals which are neither trenched nor buried should normally be entirely removed.

10.9 Any mattresses or grout bags which have been installed to protect pipelines during their operational life should be removed for disposal onshore. If the condition of the mattresses or grout bags is such that they cannot be removed safely or efficiently then any proposal to leave them in place must be supported by an appropriate comparative assessment of the options. The Department would however be willing to consider a proposal to leave any mattresses or grout bags in place if they are under the pipeline and it can be demonstrated that this would not cause a snagging protrusion above the pipeline.

10.10 In the case of rock-dump that has been used to protect a pipeline it is recognised that removal is unlikely to be practicable. It is assumed therefore that rock-dump will remain in place, unless there are special circumstances that would warrant consideration of removal. If the rock-dump is associated with a pipeline that is being left in place then it would be expected that the rock-dump would remain undisturbed. If, however, it is associated with a pipeline that is being removed then minimum disturbance of the rock-dump to allow safe removal of the pipeline and the elimination of any seabed obstruction that may result from the presence of the rock, would be expected.

Monitoring

10.11 Pipelines decommissioned in place will be subject to a suitable monitoring programme agreed with DECC in consultation with other Government Departments. Details should be specified in the decommissioning programme. The form and duration of the monitoring programme will depend upon the prevailing circumstances and, if necessary, be adapted with time. However a typical monitoring regime should commence with a post-decommissioning survey at the completion of decommissioning work. Following all surveys, inspection reports should be submitted to DECC's Offshore Decommissioning Unit. If these show the existence of potential hazards to other users of the sea then proposals for appropriate maintenance or remedial work should also be included

10.12 Following a DECC commissioned study to determine the appropriate requirements for long term monitoring of these lines the Department has concluded that a risk based monitoring scheme based on pipeline stability and potential impact remains appropriate for lines which are decommissioned in place. Each pipeline must be judged on its individual burial history and condition when establishing a monitoring scheme. Inspections of pipelines should then be undertaken for a fixed period depending on the risk criteria after which time they may move to a reactive basis i.e. surveys only if concerns arise about the pipeline. As part of this process DECC will be closely involved with the Operator during the monitoring phase and will review the findings of reports in consultation with other Government Departments and fishermen representatives before deciding whether a reactive basis is appropriate.

Deferral

10.13 In those cases where a pipeline reaches the end of its operational life before other facilities in the field, the Operator should notify DECC's Offshore Decommissioning Unit that the pipeline is no longer in use. DECC will send the Operator a Disused Pipeline Notification form requesting details on the status of the pipeline that has been taken out of use. The Disused Pipeline Notification has been drawn up in consultation with the Scottish Government - Marine Scotland, the Department of Environment, Food and Rural Affairs, the Health and Safety Executive and Oil & Gas UK. Upon receipt of this information DECC in discussion with other Government Departments, including the SG-MS, DEFRA and HSE, will consider whether a decommissioning programme for the pipeline is appropriate at this stage or whether its final decommissioning can be dealt with at end of field life along with the other facilities in the field.

10.14 Amongst the factors to be taken into account in deciding the approach to a redundant pipeline in these circumstances will be the length, diameter and construction of the pipeline; its location and the extent to which the pipeline is trenched or buried; and the stability and integrity of the pipeline including the presence of any spans in excess of 0.8 metres in height and 10 metres in length and/or which are likely to present a hazard to fishing activity.

10.15 If it is agreed that final decommissioning may be delayed until a more appropriate time, DECC will issue a letter setting out the conditions upon which it is prepared to defer formal decommissioning. This may include the requirement to carry out remedial work on the pipeline. DECC will wish to be satisfied that leaving the pipeline in place until end of field life will not prejudice any final decommissioning solution – including complete removal - and that the pipeline will be subject to an appropriate surveying and maintenance regime. Following future surveys DECC will write to the operator to confirm the status of the pipeline.

10.16 In cases where decommissioning is deferred as detailed above, the pipelines concerned are considered to form part of the Interim Pipeline Regime.

(Further details are available on DECC's Oil & Gas Website[*http://www.og.decc.gov.uk/upstream/decommissioning/decom2.htm*](http://www.og.decc.gov.uk/upstream/decommissioning/decom2.htm) *).*

Consultation

10.17 The consultation arrangements set out in *Section 6* apply equally to pipeline decommissioning programmes.

Territorial Sea

10.18 Pipelines that cross the UK seabed within the territorial sea (12 nautical miles from the UK coastline) are likely to be subject to a lease granted by The Crown Estate which will include a rental payment based upon the size of the pipeline. Operators may apply to The Crown Estate for termination of the rent upon completion of decommissioning works or suspension of the rent if the pipeline has fallen into temporary disuse.

11. DRILL CUTTINGS

11.1 Many offshore installations located on the UKCS, particularly in the northern sector of the North Sea, have significant volumes of drill cuttings deposited on the seabed beneath them. In some cases the 'footings' of the jacket are embedded within a cuttings pile and any attempt to entirely remove the installation will be impossible without disturbance or removal of the drill cuttings piles.

11.2 In 1998, in response to concerns Oil & Gas UK initiated an industry study of the issues associated with the accumulation of drill cuttings beneath offshore installations. The study was completed and the results presented to OSPAR in February 2002. Further information on the work undertaken and the outcomes is available from the Oil & Gas UK website (www.oilandgasuk.co.uk).

11.3 Following presentation of the study, OSPAR agreed that Contracting Parties should consider with their industries the feasibility of surveying representative cuttings accumulations so as to provide an indication of the environmental impacts of individual piles. As a result, a joint industry initiative involving a sampling cruise of various UKCS fields was undertaken in 2004. The results of this survey, along with an outline management regime reflecting the survey outcomes were presented to OIC 2005 and the UK developed a proposal for OIC 2006 adopted as OSPAR Recommendation 2006/5 *(See Annex I).*

11.4 The Recommendation had effect from 30 June 2006 and introduced a two stage management regime. Stage 1 provided for initial screening of all cuttings piles, to be completed by 30 June 2008 to identify any piles that require further investigation based on the thresholds set out in the Recommendation. Industry's subsequent report assessing UK cuttings piles in line with the Recommendation concluded that they were all below the specified thresholds. These results were submitted as part of DECC's implementation report to OIC 2009 and have informed the UK strategy. There is no need for immediate remediation of UK drill cuttings. However, at the time of decommissioning the associated installations the characteristics of the relevant cuttings piles should be assessed in detail and the need for further action in line with Stage 2 of the Recommendation reviewed, see next paragraph.

11.5 A draft decommissioning programme should record the outcome of Stage 1 screening for any cutting piles present under the installation(s). If the Stage 1 assessment was based on extrapolation of data for the piles, the results should be verified with survey data for the piles in question. Where either threshold in Recommendation 2006/5 is exceeded, Stage 2 will apply and will require a study, including a comparative assessment, to determine the best option for handling the cuttings pile. DECC will agree the time at which Stage 2 should be initiated, taking account of the rate of oil loss, the persistence and the timing of decommissioning of the associated installations *(See Annex C for further details).*

12. ENVIRONMENTAL CONSIDERATIONS

Environmental Impact Assessments

12.1 Although there is currently no statutory requirement to undertake an Environmental Impact Assessment (EIA) at the decommissioning stage, a decommissioning programme will nevertheless need to be supported by an EIA. The Environmental Statement (ES) submitted for the development under the EIA regulations requires the applicant to consider the long-term impacts of the development and these include the impacts arising from decommissioning. However, in the light of the lengthy period of time between project sanction and decommissioning, the requirement for a detailed assessment is deferred until closer to the time of actual decommissioning and is submitted as part of the decommissioning programme. In the case of an OSPAR derogation candidate it will be necessary to address through the EIA the environmental impacts of alternative disposal options as part of the Comparative Assessment. However, in the majority of cases where total removal applies and a Comparative Assessment is not required it will only be necessary for the EIA to address the impacts of the proposed decommissioning activity on the environment. *Further details on the information that should be included in an EIA are set out in Annex C (see also Annex A).*

Environmental Regulations

12.2 During the development, consideration and implementation of the decommissioning programme, operators should discuss the proposals with DECC's Offshore Environment Unit, to determine whether the following regulations are relevant to the proposed works, and to discuss the procedures for obtaining or surrendering any relevant permits. *Separate, detailed guidance can be found on* http://www.og.decc.gov.uk/environment/index.htm

The Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001

12.3 These regulations apply the Habitats Directive and the Wild Birds Directive in relation to offshore oil and gas plans and projects wholly or partly on the UKCS. The regulations apply to decommissioning proposals and in the light of the information provided in the ES, DECC in consultation with the Joint Nature Conservation Committee (JNCC) and/or the Countryside Agencies (Natural England, Countryside Council for Wales and Scottish Natural Heritage), will decide whether the proposals are likely to have a significant effect on the habitats and species covered by the regulations, and whether there is a requirement to undertake an 'Appropriate Assessment'. It should be noted that the regulations do not apply to artificial habitats created by the infrastructure that is the subject of the decommissioning programme, and it will therefore be unnecessary to justify the removal of structures that have been colonised by protected or rare species. However, it is still a requirement to conduct surveys to establish whether such species or habitats are present and to what extent. If their presence is significant an Appropriate Assessment may still be required and it will be necessary to understand what mitigation measures would be appropriate. *(See also paragraph 12.11 and Annex C, paragraph10).*

The Offshore Chemical Regulations 2002

12.4 These regulations implement, OSPAR Decision 2000/2 on a Harmonised Mandatory Control System for the Use and Reduction of the Discharge of Offshore Chemicals. Where it is proposed to use or discharge chemicals during the decommissioning of an offshore installation or pipeline, the Operator will need to apply to DECC for the appropriate permit. The application should be submitted using a PON 15E or, if chemical use and discharge is minimal, using an existing PON 15D to request a variation of the production chemical permit.

The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005

12.5 These regulations prohibit the discharge of oil into the sea from an offshore installation or pipeline, except under authority of a permit. Operators will be required to make provision for the removal and recycling of oil recovered during the decommissioning, but it will be possible to apply for a permit for the discharge or reinjection of certain types and quantities of oil. Applications should be submitted to DECC, using the standard OPPC application form. Further guidance is available at: http://www.og.decc.gov.uk/environment/opaoppcr.htm

The Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2001

12.6 These regulations implement the Integrated Pollution Prevention and Control (IPPC) Directive for offshore oil and gas installations. Under the regulations a permit is required from DECC if the aggregated thermal capacity of the combustion equipment on the installation exceeds 50 MW(th). Such permits will have been issued prior to decommissioning and when the aggregated thermal capacity of the relevant plant falls below the 50 MW(th) threshold during the course of the decommissioning operations, the installation will no longer be subject to the controls and the Operator will be required to surrender the permit.

The Greenhouse Gases Emission Trading Scheme (ETS) Regulations 2003

12.7 These regulations implement the EU Emissions Trading Scheme (EUETS). Under the regulations, operators are required to apply to DECC for a permit covering the emission of greenhouse gases (currently only CO_2), if the aggregated thermal capacity of the combustion equipment on the installation exceeds 20 MW(th). Such permits will have been issued prior to decommissioning, and must be surrendered when the aggregated thermal capacity falls below the threshold. The installation will then be deemed "closed", and will drop out of the EU Emissions Trading Scheme. Installations will be able to retain and trade any surplus allowances for the year of "closure", i.e. when they fall below the threshold and drop out of the Scheme, but will not receive any allowances for future years.

The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998

12.8 Under these regulations operators of offshore oil and gas installations and pipelines are responsible for preparing and submitting an Oil Pollution Emergency Plan (OPEP) to DECC. The expectation is that the OPEP will cover all activities where there is a risk of a hydrocarbon spill, including activities relating to decommissioning. This may be achieved by the incorporation of decommissioning activities into the existing field OPEP or by producing a decommissioning specific OPEP.

Environmental Surveys

12.9 Surveys around an installation to establish an environmental baseline may need to be undertaken before decommissioning if relatively recent survey data does not already exist. In most cases, it is unlikely that a new baseline survey would be required if a relevant survey has been undertaken in the last five years. It should be noted that the scope of existing or proposed baseline surveys should be comparable to the requirements in paragraph 12.16.

12.10 Precise requirements will differ according to individual conditions. Discussions on what may be required in an individual case should be held with DECC's Offshore Decommissioning Unit before an Operator develops the survey strategy.

Lophelia pertusa/Sabellaria

12.11 The coldwater coral, *Lophelia pertusa* and reef forming worm *Sabellaria* are known to exist on or around offshore installations. The coral and *Sabellaria* are species of conservation interest and surveys may be necessary to establish their presence. As with all marine species, if there is a significant growth of coral or an established *Sabellaria* reef the potential impact of the operations on these species should be assessed in the EIA. An Appropriate Assessment may also be conducted. *(See also Annex C, paragraph10).* If the coral is present and the installation upon which it is located is to be returned to shore it will be necessary to discuss with DEFRA the requirements of the Convention on International Trade in Endangered Species. *(See also Annex D).*

Debris clearance

12.12 Upon completion of each decommissioning operation, appropriate surveys should be undertaken to identify and recover any debris located on the seabed which has arisen from the decommissioning operation or from past development and production activity.

12.13 The area to be covered will depend on the circumstances of each case. However, the minimum required will be a radius of 500 metres from the location of an installation.

12.14 Debris surveying and removal may be required up to 100 metres either side of a decommissioned pipeline over its whole length.

12.15 Following the removal of any debris, independent verification of seabed clearance will be required. The advisability of post-decommissioning over-trawling to confirm that the area is clear of debris will be considered on a case-by-case basis and will be dependent upon the extent of any cuttings piles and any other relevant circumstances.

Sampling post-decommissioning

12.16 In addition to debris surveys, a post-decommissioning environmental seabed sampling survey should be undertaken, in particular to monitor levels of hydrocarbons, heavy metals and other contaminants in sediment and biota.

12.17 In each case, operators should develop their survey strategy in consultation with DECC's Offshore Decommissioning Unit who will take specialist advice from DECC colleagues and other Government Departments.

12.18 Details of the survey strategy should be included in the decommissioning programme.

12.19 In most cases a second survey will need to be undertaken some time after the post-decommissioning sampling. Any further surveys will depend upon the results of earlier work and the circumstances of each case.

Reporting

12.20 The results of all surveys should be submitted to DECC's Offshore Decommissioning Unit. These will normally be included in the post-decommissioning Close-out report referred to in Section 13. Verification of seabed clearance will also be necessary and may be provided in the form of a seabed clearance certificate issued by an independent party. A copy of the seabed clearance certificate should also be submitted to the Seabed Data Centre (Offshore Installations) at the United Kingdom Hydrographic Office *(see Section 15 for full address)*.

13. CLOSE OUT REPORTS

13.1 At the conclusion of decommissioning operations the Operator will be required to satisfy DECC that the approved programme has been implemented. This will involve the submission of a Close-out Report within four months of the completion of offshore work, including debris clearance and post-decommissioning surveys. The report should explain major variations from the decommissioning programme and should summarise the following:

- Information on the outcome of the decommissioning programme as a whole. This should outline how the major milestones were achieved. This information should provide confirmation that work has been carried out in accordance with the terms of the programme.

- An explanation of any major variances from the programme including why they occurred and an indication of any permits required as a result. Where appropriate include exact quantities of recovered hydrocarbons, sludges, heavy metals, sacrificial anodes and radioactive material including LSA (Low Specific Activity) scale.

- The results of debris clearance and any monitoring undertaken. Any independent verification (e.g. seabed clearance certificates) should be attached.

- The results of the post-decommissioning environmental sampling survey including any immediate consequences of the decommissioning activity which have been observed. If necessary update the schedule for future environmental monitoring or monitoring of items left in place with reasons for the changes.

- Measures taken to manage the potential risks arising from any legacies, including participation in the Fisheries Legacy Trust Company (see Section 16.4), confirmation of marking any remains on mariners charts, inclusion in the 'Fishsafe' system and installation of navigational aids.

- Provide high level summary of actual costs and a general explanation of any difference against forecast costs.

13.2 Following submission of the Close-out Report to DECC the Operator will be asked to place a copy on their website. DECC will send a letter to the Operator to confirm acceptance of the close-out report. HM Revenue and Customs will regard DECC's acceptance of the close-out report as marking the completion of the project for tax purposes.

13.3 Companies should also remember that geotechnical data collected under the petroleum licence should either be placed in the National Hydrocarbons Data Archive (NHDA, http://www.bgs.ac.uk/nhda/) or kept in perpetuity in accordance with the licence model clauses. The NHDA option should normally be considered at Cessation of Production. Further information regarding data storage requirements can be found at section 6.6 of the 'Guidance Notes of Procedures for Regulation of Offshore Oil and Gas Developments' which can be viewed on DECC's Oil & Gas Website at https://www.og.decc.gov.uk/regulation/guidance/index.htm

14. POST-DECOMMISSIONING MONITORING OF REMAINS

14.1 If, following OSPAR consultation procedures, it is agreed that a concrete installation or the 'footings' of a steel installation should be left in place, the condition of the remains will have to be monitored at appropriate intervals by the owners. A suitable monitoring regime should be agreed with DECC who will consult other Government Departments and Agencies with an interest. Details of the monitoring regime should be specified in the decommissioning programme.

14.2 The form and duration of the monitoring programme will depend upon the particular circumstances and if necessary will be adapted with time. Inspection reports should be submitted to DECC's Offshore Decommissioning Unit together with proposals for any maintenance or remedial work that may be required. The reports should also be published by appropriate means (e.g. on the internet).

14.3 In accordance with Annex 4 to the OSPAR Decision (which sets out the conditions to be attached to any permits granted in accordance with the Decision), the first step in any monitoring programme has to be taken *before* decommissioning operations begin. Annex 4 requires independent verification that the condition of the installation before the disposal operation commences is consistent with both the terms of the Secretary of State's approval and the information upon which the assessment of the proposed disposal is based. This will include details of the fate of any hazardous substances. The approach to this requirement will be addressed on a case by case basis. It will be for the Operator to propose a suitable organisation to carry out the independent verification.

14.4 In accordance with paragraph 10 of the OSPAR Decision it will be necessary for DECC to submit to OSPAR a post-disposal report indicating how the disposal operation was carried out, any immediate consequences of the disposal which have been observed and confirmation that the disposal has been implemented in accordance with the terms of the decommissioning programme. This report must be submitted within 6 months of the completion of the disposal. It will be drafted by DECC based on the Operator's Close-out report *(see Section 13 of this guidance).* DECC will provide the Operator with the opportunity to review the report before it is submitted to OSPAR.

14.5 Any pipelines left in place will also be subject to a monitoring regime agreed with DECC as part of the decommissioning programme (*see Section 10 of this guidance*).

15. MARKING OF REMAINS AND SAFETY ZONES

15.1 It is the Operator's responsibility to ensure that at least 6 weeks advance notification of the change in status of decommissioned installations and pipelines is given to:

The United Kingdom Hydrographic Office
Seabed Data Centre (Offshore Installations)
Admiralty Way
Taunton
Somerset
TA1 2DN

so that mariners may be advised and appropriate amendments made to charts.

15.2 In those cases where it is agreed that a concrete installation, the 'footings' of a steel installation or a pipeline should remain in place, the Operator must ensure that the position (horizontal datum to be stated), surveyed depth and dimensions of the remains are forwarded immediately to the Hydrographic Office, for inclusion on Admiralty charts. In addition, the Hydrographic Office Radio Navigation Warnings (RNW) section should be contacted 24 hours in advance of offshore activity concerning the removal and tow of platforms, FPSOs and other surface structures. The RNW duty officer can advise on details required and can be contacted on Tel: 01823 353448 (email: navwarnings@btconnect.com

15.3 It should be noted that drill cuttings accumulations will only be marked on Admiralty charts if it is considered that they present a danger to surface navigation or alter the charted seabed depth significantly. In such cases they would be recorded as a 'foul' or 'shoal depth'. Details of any cuttings piles that may fall into this category should be discussed with the Hydrographic Office.

15.4 It is the Operator's responsibility to install and maintain navigational aids for any remains of concrete installations that project above the surface of the sea. The nature of the navigational aids to be employed should be discussed with DECC, the relevant lighthouse authorities and with interested parties such as fishermen and other mariners. It is the Operator's responsibility to ensure the maintenance of any such navigational aids. Details of the action to be taken to advise mariners and mark any remains should be included in the decommissioning programme; the Hydrographic Office should be kept informed.

Safety Zones

15.5 A safety zone is an area of 500m radius established automatically around all offshore oil and gas installations which project above the sea at any state of the tide. Vessels of all nations are required to respect them. It is an offence (under section 23 of the Petroleum Act 1987) to enter a safety zone except under special circumstances. The zone stays in place during the decommissioning period and only ceases when the structure no longer projects above the surface of the sea. Any doubt about the continuation of a safety zone during decommissioning work should be discussed with the HSE.

15.6 Safety zones around some installations emplaced before the introduction of the Petroleum Act 1987 were created by statutory instrument. The establishment of a safety zone around a sub-sea installation is also made by statutory instrument and application should be made to the HSE who will arrange consultation with other Government Departments. Following decommissioning it will be necessary to apply to the HSE for removal of a zone established by statutory instrument. If subsequently it becomes necessary to undertake any work on facilities that remain in place, the safety zone can be re-established to cover these works.

16. RESIDUAL LIABILITY AND DECOMMISSIONING LEGACIES

16.1 The persons who own an installation or pipeline at the time of its decommissioning will remain the owners of any residues. Any residual liability remains with the owners in perpetuity. In addition, those with a duty to secure the decommissioning programme is carried out will remain responsible for complying with any conditions attached to the Secretary of State's approval of the decommissioning programme. In cases of potential default where the Secretary of State is concerned that the current parties may no longer be able to carry out the approved programme he will consider whether to utilise section 34 of the Petroleum Act 1998 to give additional companies an obligation to carry out the work. Section 3 of this guidance provides further information regarding the use of section 34. Essentially any company that was previously in receipt of a section 29 notice for the equipment covered by the programme, or any person on whom notices could have been served since the serving of the first section 29 notice could be added as a party to the programme. This is a measure of last resort and only used in a potential default situation where significant work under the programme is necessary.

16.2 Any remains of installations or pipelines will be subject to monitoring at suitable intervals as specified in each decommissioning programme (*see Sections 10 and 14 of this guidance*) and may require maintenance or remedial action in the longer term. Such action may be the subject of a revision to the programme. Should remedial action be considered as a result of significant advances in technology a comparative assessment would need to be carried out to determine the benefits of such action in relation to safety, technical, environmental, social and cost aspects.

16.3 Any claims for compensation by third parties arising from damage caused by any remains will be a matter for the owners and the affected parties and will be governed by the general law.

16.4 Measures to manage the potential risks arising from any legacies should be addressed in the decommissioning programme. Legacies arising from offshore oil and gas activity have particular implications for fishermen. As a result, the oil and gas industry, through Oil & Gas UK, and fisherman's representatives have established a Fisheries Legacy Trust Company. This may manage some post-decommissioning activities and legacies and assists both industries to work safely and efficiently together by promoting harmonious working relations. Where the Trust Company is used to manage activities associated with a decommissioning project this should be reflected in the programme. *See the following links for more information*
http://www.oilandgasuk.co.uk/knowledgecentre/Fisheries.cfm
http://www.ukfltc.com/home.aspx

16.5 The relinquishment of the field licence is not related to completion of a decommissioning programme or any ongoing liabilities under it. The timing of relinquishment is a separate matter which should be discussed with DECC's Licensing Unit.

17. INDUSTRY CO-OPERATION AND SYNERGY

17.1 The Government encourages Industry co-operation and collaboration at the decommissioning stage in order to minimise its various impacts. The decommissioning phase, where the competitive pressures are less than at the development and production stage, offers an ideal opportunity for companies to share decommissioning expertise. This can range from co-operation on studies or the exchange of information or ideas to collaboration on specific decommissioning projects and proposals. Oil & Gas UK, the Pilot Initiative and The Early Decommissioning Synergy Group (TEDS) all promote co-operation. In discussing decommissioning proposals with operators, DECC will also seek to identify opportunities for co-operation wherever possible.

17.2 The development of new technology and new techniques to tackle the challenges that arise at the decommissioning stage will be particularly important. Much research and development work has already been done or is currently underway. The joint industry Decommissioning Technology Forum (DTF) has played an important part in identifying and developing specific areas of technology. The Industry Technology Facilitator (ITF) is identifying technology needs for the decommissioning phase and promoting their development and implementation. *Further information on the ITF is available from the following link: http://www.oil-itf.com/*

18. THE UK OIL PORTAL

18.1 In line with UK Government policy for all business processes to be carried out electronically, the UK Oil Portal provides authenticated access to the e-commerce systems of DECC's Energy Development Unit. The Portal provides a secure electronic environment which allows industry to apply for and receive consent or direction on a wide range of activities relating to hydrocarbon exploration, production, development, decommissioning and the protection of the environment.

18.2 The serving of notices under section 29 of the Petroleum Act 1998 *(see Section 3)* was transferred to the Portal in 2007. Other key decommissioning procedures will move to the Portal in due course.

18.3 Benefits of using the Portal for section 29 processes:

- makes the process more efficient by making electronic notifications immediately and concurrently available to all relevant parties, irrespective of their geographical location.
- contacts have 24 hour worldwide access to details of all section 29 notices issued to their company.
- takes advantage of a paperless transaction.
- provides a reliable audit of the notification process with accountability.
- provides the Offshore Decommissioning Unit with a direct and simple mechanism to disseminate relevant information to S29 Portal Contacts.
- provides easy access to support for both the business process and the information technology side.

18.4 For further details regarding Portal accounts for section 29 processes contact julie.benstead@decc.gsi.gov.uk (tel. 01224 254034). Account holders will only be given access to information relevant to their company.

19. PROVISION FOR HISTORICALLY IMPORTANT RECORDS

19.1 In March 2006 an initiative began to establish an archive of the UK offshore oil and gas industry with the aim of ensuring that important record material is preserved for future generations.

19.2 The idea evolved from a scheme already underway in Norway relating to records of the UK/Norwegian Frigg gas field, which ceased production in 2004. The UK project was launched at a successful conference 'Capturing the Energy' held in Aberdeen in March 2006. The conference urged wider recognition of the huge importance of the offshore oil and gas industry through the creation and exploitation of a UK archive.

19.3 The intention is that companies will make provision for keeping the most important records as their operations evolve, ensuring that they can be safely stored, in a centralised archive repository, or network of repositories, so that they can be made accessible both within the sector and wider community for current research and future generations.

19.4 A number of organisations have given their support to the initiative, including – Oil & Gas UK, major oil companies, Scottish Enterprise Grampian, the Royal Commission on the Ancient and Historical Monuments of Scotland (RCAHMS), the Business Archives Council of Scotland (BACS), Historic Scotland, Mearns and Gill, the University of Aberdeen and Aberdeen City Council. The hub of the archival network will be at the University of Aberdeen which has strong links with the sector.

19.5 DECC fully supports the scheme and recognises that decommissioning represents a key milestone which provides the opportunity to ensure that important data relating to the life of a field development and operations is preserved for the future. DECC has identified those projects which are of particular importance in this respect, and would encourage operators to discuss their records and information with the Capturing the Energy initiative.

19.6 Further details can be obtained from:

Capturing the Energy
Special Libraries & Archives
King's College
Aberdeen
AB24 3SW

http://www.capturing-the-energy.org.uk/
Email: info@capturing-the-energy.org.uk
Phone: +44 (0)1224 272972
Fax: +44 (0)1224 273891

ANNEX A

ASSESSMENT CRITERIA FOR OSPAR DEROGATION CANDIDATES

1. OSPAR Decision 98/3 recognises that there may be difficulty in removing the 'footings' of large steel jackets weighing more than 10,000 tonnes and in removing the substructures of concrete installations. Exceptional and unforeseen circumstances resulting from structural damage or deterioration or equivalent difficulties may also prevent an installation from being totally removed. As a result there is provision for derogation from the general rule of re-use, recycling or final disposal on land for these categories of installations.

2. If an installation falls within the derogation categories then a detailed assessment of the alternative disposal options must be carried out by the Operator. The framework for this assessment is set out in Annex 2 to the OSPAR Decision and includes an indication of the matters to be taken into account in assessing the disposal options.

3. For the matters identified in Annex 2 to the OSPAR Decision, operators should require the impact of each option to be assessed using established methodologies. The preferred option should be selected by focusing on the matters where the impacts of the options are significantly different. The means used to reach the conclusion should be described.

4. The presumption in the OSPAR Decision is that all installations will be removed. It is important therefore in comparing the options for derogation candidates to start from a baseline of complete removal. If the comparative assessment of the options identifies two or three matters that show a significant difference, judgement will need to be exercised as to which should be given the greatest consideration. There is no outright hierarchy, although balancing the safety and environmental impacts of the options, including the impact on climate change, will clearly be important. Options where the safety risks are intolerable or involve major unacceptable environmental impacts may be ruled out without further consideration. Proportionality must also be considered but it is unlikely that cost will be accepted as the main driver unless all other matters show no significant difference. The engagement of interested stakeholders in balancing the impacts of the options is strongly recommended.

5. The following Matrix and supporting information is designed to assist with the process and provide further information on the criteria that may be applied in carrying out an assessment of the options. The intention is to provide greater consistency to the evaluation of derogation cases, ensure transparency and in turn provide greater confidence in the derogation process.

6. Following detailed assessment of the options against the OSPAR framework the Operator may wish to present the outcomes in the form of the Matrix below or adapt it to the particular circumstances of the case. Inclusion of such a Matrix in the decommissioning programme together with an explanation of the basis for the ranking of the matters to be considered for each

decommissioning option will help to provide a clear overall indication of the acceptability of the derogation case.

7. Companies and government will also wish to take account of reputational issues from their own perspective. These are important considerations and may well influence the final decision. However, they should not be included in the comparative assessment process but addressed in a wider context and separately from the decommissioning programme.

		DECOMMISSIONING OPTIONS											
ASSESSMENT CRITERIA	**Matters to be considered**	Complete removal to land			Partial removal to land			Leave wholly in place			Disposal at sea *		
Safety	risk to personnel												
	risk to other users of the sea												
	risk to those on land												
Environmental	marine impacts												
	other environmental compartments (including emissions to the atmosphere)												
	energy/resource consumption												
	other environmental consequences (including cumulative effects)												
Technical	risk of major project failure												
Societal	fisheries impacts												
	amenities												
	communities												
Economic													
	HIGH	**MEDIUM**						**LOW**					

* Although under OSPAR Decision 98/3 the disposal of the substructure of a concrete installation at a deep-water licensed site is still an option this must be considered against the UK Government announcements at the time of the Decision when Ministers stated that there would be no toppling and no local or remote dumping of offshore installations.

NOTES

Safety:

- In assessing and comparing the safety risks of different options the general principles of risk management used within the industry should be applied.

- The use of quantitative risk assessment (QRA) techniques should be employed. Typical mechanisms include using Potential Loss of Life (PLL), Individual Risk Per Annum (IRPA) and Fatal Accident Rate (FAR) criteria.

- Comparison should be made with the risk levels generally supported by the Health & Safety Executive who define the maximum tolerable level of individual risk of fatality as 1 in 1000 per year, and for the broadly acceptable level of individual risk to be set in the range of 1 in 100,000 to 1 in 1 million per year.

- Where different corporate risk levels to those indicated above have been adopted, comparison should also be made with these.

The risks should also be set in context by drawing comparison with the risks that were judged to be acceptable during the installation and development phase and the risks that exist in other industries.

Environmental:

- The assessment and comparison of the environmental impacts of different options should be based on an Environmental Impact Assessment (EIA) carried out in accordance with the widely recognised techniques and standard methodologies for such evaluations. This should include consideration of the impact on climate change.

- DECC's Guidelines on the preparation of Environmental Statements provides further guidance (http://www.og.decc.gov.uk/environment/opppr_2007.htm).

- An assessment of the impact of all activities at the offshore location and also at the onshore dismantling and disposal site should be carried out. If the disposal site is not known, a generic assessment of environmental impacts at a typical disposal site should be carried out.

- In assessing energy and resource consumption, as well as any discharges or emissions to the environmental compartments, the internationally agreed principles for environmental life cycle assessments should be followed.

Technical feasibility:

Recognised QRA techniques, engineering and operational analysis should be used in combination to provide comprehensive, robust, quantitative and qualitative assessments of the options.

- Comparison should be made with accepted industry risk assessment criteria for marine operations. Consideration of the risks associated with the work will include evaluation of the maximum acceptable probability of a major accident, judged against corporate standards and where possible the criteria adopted during the installation phase.

- The assessment of the technical feasibility of different decommissioning options should be based on existing industry experience and available equipment. But where possible account should also be taken of the planned timing of the work and foreseeable developments in technology.

Societal

- The engagement of interested stakeholders will be important in order to assess and take account of the views of different interest groups. The Oil & Gas UK Guidelines on Stakeholder Engagement for Decommissioning Activities should be consulted at http://www.oilandgasuk.co.uk/

- The impacts on fisheries and fishing activity will be of particular importance. This should be assessed with regard to the level of activity in the area and the long-term impacts, the safety of fishermen and mitigation measures that can be put in place.

- Employment and regional development opportunities should be considered.

Economic

- Establishing accurate cost estimates is important not only from a company point of view but for Government given that under the UK tax regime a significant proportion of decommissioning costs ultimately falls to the Exchequer.

- In preparing cost estimates, account should be taken of the work undertaken in workgroup 4 of the Pilot Brownfields initiative to establish a common approach to decommissioning costs. Guidelines are available on the Oil & Gas UK website http://www.oilandgas.co.uk/

- In assessing alternative decommissioning options proportionality should be considered and costs should be balanced against the other assessment criteria. However, it is unlikely that costs alone will be accepted as the deciding factor in arriving at the preferred option unless all other matters show no significant difference.

Verification

In addition to stakeholder engagement it is important that the studies and the assessment process that supports the chosen decommissioning option are subject to independent expert verification. The purpose of this verification is to confirm that the assessments are reliable and there is no requirement to verify the final means of weighting and balancing the options but the process must be transparent. This may involve the establishment of an independent review process to evaluate the scope, quality and application of the work undertaken. Experts in particular fields may be engaged to evaluate and confirm specific aspects of the project.

DECC may itself engage consultants to test particular aspects of the decommissioning proposals or to confirm that accepted practices and methodologies have been used.

OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations

RECALLING the Convention for the Protection of the Marine Environment of the North East Atlantic, in particular Articles 2 and 5 of that Convention,

RECALLING the relevant provisions of the United Nations Convention on the Law of the Sea,

RECOGNISING that an increasing number of offshore installations in the maritime area are approaching the end of their operational life-time,

AFFIRMING that the disposal of such installations should be governed by the precautionary principle, which takes account of potential effects on the environment,

RECOGNISING that re-use, recycling or final disposal on land will generally be the preferred option for the decommissioning of offshore installations in the maritime area,

ACKNOWLEDGING that the national legal and administrative systems of the relevant Contracting Parties need to make adequate provision for establishing and satisfying legal liabilities in respect of disused offshore installations,

THE CONTRACTING PARTIES TO THE CONVENTION FOR THE PROTECTION OF THE MARINE ENVIRONMENT OF THE NORTH EAST ATLANTIC DECIDE THAT

Definitions

1. For the purposes of this Decision, "concrete installation" means a disused offshore installation constructed wholly or mainly of concrete;

"disused offshore installation" means an offshore installation, which is neither

a. serving the purpose of offshore activities for which it was originally placed within the maritime area, nor
b. serving another legitimate purpose in the maritime area authorized or regulated by the competent authority of the relevant Contracting Party;

but does not include:

c. any part of an offshore installation which is located below the surface of the sea-bed, or
d. any concrete anchor-base associated with a floating installation which does not, and is not likely to, result in interference with other legitimate uses of the sea;

"relevant Contracting Party" means the Contracting Party, which has jurisdiction over the offshore installation in question;

"steel installation" means a disused offshore installation, which is constructed wholly or mainly of steel;
"topsides" means those parts of an entire offshore installation which are not part of the substructure and includes modular support frames and decks where their removal would not endanger the structural stability of the substructure;

"footings" means those parts of a steel installation which:

(i) are below the highest point of the piles which connect the installation to the sea-bed;

(ii) in the case of an installation built without piling, form the foundation of the installation and contain amounts of cement grouting similar to those found in footings as defined in sub-paragraph 3(a); or

(iii) are so closely connected to the parts mentioned in subparagraphs (i) and (ii) of this definition as to present major engineering problems in severing them from those parts.

Programmes and Measures

2. The dumping, and the leaving wholly or partly in place, of disused offshore installations within the maritime area is prohibited.

3. By way of derogation from paragraph 2, if the competent authority of the relevant Contracting Party is satisfied that an assessment in accordance with Annex 2 shows that there are significant reasons why an alternative disposal mentioned below is preferable to re-use or recycling or final disposal on land, it may issue a permit for

a. all or part of the footings of a steel installation in a category listed in Annex 1, placed in the maritime area before 9 February 1999, to be left in place;

b. a concrete installation in a category listed in Annex 1 or constituting a concrete anchor base, to be dumped or left wholly or partly in place;

c. any other disused offshore installation to be dumped or left wholly or partly in place, when exceptional and unforeseen circumstances resulting from structural damage or deterioration, or from some other cause presenting equivalent difficulties, can be demonstrated.

4. Before a decision is taken to issue a permit under paragraph 3, the relevant Contracting Party shall first consult the other Contracting Parties in accordance with Annex 3.

5. Any permit for a disused offshore installation to be dumped or permanently left wholly or partly in place shall accord with the requirements of Annex 4.

6. Contracting Parties shall report to the Commission by 31 December 1999, and every 2 years thereafter, relevant information on the offshore installations

within their jurisdiction including, when appropriate, information on their disposal for inclusion in the inventory to be maintained by the Commission.

7. In the light of experience in decommissioning offshore installations, in particular those in categories listed in Annex 1, and in the light of relevant research and exchange of information, the Commission shall endeavour to achieve unanimous support for amendments to that Annex in order to reduce the scope of possible derogations under paragraph 3. The preparation of such amendments shall be considered by the Commission at its meeting in 2003 and at regular intervals thereafter.

Entry into force

8. This Decision enters into force on 9 February 1999, and shall then replace Decision 95/1 of the Oslo Commission concerning the Disposal of Offshore Installations.

Implementation Reports

9. If any Contracting Party decides to issue a permit for a disused offshore installation to be dumped or left wholly or partly in place within the maritime area, it shall submit to the Commission at the time of the issue of the permit a report in accordance with paragraph 3 of Annex 4.

10. If any disused offshore installation is dumped or left wholly or partly in place within the maritime area, the relevant Contracting Party shall submit to the Commission, within 6 months of the disposal, a report in accordance with paragraph 4 of Annex 4.

[ANNEX 1 to OSPAR Decision 98/3]

CATEGORIES OF DISUSED OFFSHORE INSTALLATION WHERE DEROGATIONS MAY BE CONSIDERED

The following categories of disused offshore installations, excluding their topsides, are identified for the purpose of paragraph 3:

a. steel installations weighing more than ten thousand tonnes in air;

b. gravity based concrete installations;

c. floating concrete installations;

d. any concrete anchor-base which results, or is likely to result, in interference with other legitimate uses of the sea.

[ANNEX 2 to OSPAR Decision 98/3]

FRAMEWORK FOR THE ASSESSMENT OF PROPOSALS FOR THE DISPOSAL AT SEA OF DISUSED OFFSHORE INSTALLATIONS

General Provisions

1. This framework shall apply to the assessment, by the competent authority of the relevant Contracting Party, of proposals for the issue of a permit under paragraph 3 of this Decision.

2. The assessment shall consider the potential impacts of the proposed disposal of the installation on the environment and on other legitimate uses of the sea. The assessment shall also consider the practical availability of re-use, recycling and disposal options for the decommissioning of the installation.

Information required

3. The assessment of a proposal for disposal at sea of a disused offshore installation shall be based on descriptions of:

   a. the characteristics of the installation, including the substances contained within it; if the proposed disposal method includes the removal of hazardous substances from the installation, the removal process to be employed, and the results to be achieved, should also be described; the description should indicate the form in which the substances will be present and the extent to which they may escape from the installation during, or after, the disposal;
   b. the proposed disposal site: for example, the physical and chemical nature of the sea-bed and water column and the biological composition of their associated ecosystems; this information should be included even if the proposal is to leave the installation wholly or partly in place;
   c. the proposed method and timing of the disposal.

4. The descriptions of the installation, the proposed disposal site and the proposed disposal method should be sufficient to assess the impacts of the proposed disposal, and how they would compare to the impacts of other options.

Assessment of disposal

5. The assessment of the proposal for disposal at sea of a disused offshore installation shall follow the broad approach set out below.

6. The assessment shall cover not only the proposed disposal, but also the practical availability and potential impacts of other options. The options to be considered shall include:

a. re-use of all or part of the installation;
b. recycling of all or part of the installation;
c. final disposal on land of all or part of the installation;
d. other options for disposal at sea.

Matters to be taken into account in assessing disposal options

7. The information collated in the assessment shall be sufficiently comprehensive to enable a reasoned judgement on the practicability of each of the disposal options, and to allow for an authoritative comparative evaluation. In particular, the assessment shall demonstrate how the requirements of paragraph 3 of this Decision are met.

8. The assessment of the disposal options shall take into account, but need not be restricted to:

a. technical and engineering aspects of the option, including re-use and recycling and the impacts associated with cleaning, or removing chemicals from, the installation while it is offshore;
b. the timing of the decommissioning;
c. safety considerations associated with removal and disposal, taking into account methods for assessing health and safety at work;
d. impacts on the marine environment, including exposure of biota to contaminants associated with the installation, other biological impacts arising from physical effects, conflicts with the conservation of species, with the protection of their habitats, or with mariculture, and interference with other legitimate uses of the sea;
e. impacts on other environmental compartments, including emissions to the atmosphere, leaching to groundwater, discharges to surface fresh water and effects on the soil;
f. consumption of natural resources and energy associated with re-use or recycling;
g. other consequences to the physical environment which may be expected to result from the options;
h. impacts on amenities, the activities of communities and on future uses of the environment; and
i. economic aspects.

9. In assessing the energy and raw material consumption, as well as any discharges or emissions to the environmental compartments (air, land or water), from the decommissioning process through to the re-use, recycling or final disposal of the installation, the techniques developed for environmental life cycle assessment may be useful and, if so, should be applied. In doing so, internationally agreed principles for environmental life cycle assessments should be followed.

10. The assessment shall take into account the inherent uncertainties associated with each option, and shall be based upon conservative assumptions about potential impacts. Cumulative effects from the disposal of installations in the maritime area and existing stresses on the marine environment arising from other human activities shall also be taken into account.

11. The assessment shall also consider what management measures might be required to prevent or mitigate adverse consequences of the disposal at sea, and shall indicate the scope and scale of any monitoring that would be required after the disposal at sea.

Overall assessment

12. The assessment shall be sufficient to enable the competent authority of the relevant Contracting Party to draw reasoned conclusions on whether or not to issue a permit under paragraph 3 of this Decision and, if such a permit is thought justified, on what conditions to attach to it. These conclusions shall be recorded in a summary of the assessment which shall also contain a concise summary of the facts which underpin the conclusions, including a description of any significant expected or potential impacts from the disposal at sea of the installation on the marine environment or its uses. The conclusions shall be based on scientific principles and the summary shall enable the conclusions to be linked back to the supporting evidence and arguments. Documentation shall identify the origins of the data used, together with any relevant information on the quality assurance of that data.

CONSULTATION PROCEDURE

1. A relevant Contracting Party which is considering whether to issue a permit under paragraph 3 of this Decision shall start this consultation procedure at least 32 weeks before any planned date of a decision on that question by sending to the Executive Secretary a notification containing:

   a. an assessment prepared in accordance with Annex 2 to this Decision, including the summary in accordance with paragraph 12 of that Annex;
   b. an explanation why the relevant Contracting Party considers that the requirements of paragraph 3 of this Decision may be satisfied;
   c. any further information necessary to enable other Contracting Parties to consider the impacts and practical availability of options for re-use, recycling and disposal.

2. The Executive Secretary shall immediately send copies of the notification to all Contracting Parties.

3. If a Contracting Party wishes to object to, or comment on, the issue of the permit, it shall inform the Contracting Party which is considering the issue of the permit not later than the end of 16 weeks from the date on which the Executive Secretary circulated the notification to the Contracting Parties, and shall send a copy of the objection or comment to the Executive Secretary. Any objection shall explain why the Contracting Party which is objecting considers that the case put forward fails to satisfy the requirements of paragraph 3 of this Decision. That explanation shall be supported by scientific and technical arguments. The Executive Secretary shall circulate any objection or comment to the other Contracting Parties.

4. Contracting Parties shall seek to resolve, by mutual consultations, any objections made under the previous paragraph. As soon as possible after such consultations, and in any event not later than the end of 22 weeks from the date on which the Executive Secretary circulated the notification to the Contracting Parties, the Contracting Party proposing to issue the permit shall inform the Executive Secretary of the outcome of the consultations. The Executive Secretary shall forward the information immediately to all other Contracting Parties.

5. If such consultations do not resolve the objection, the Contracting Party which objected may, with the support of at least two other Contracting Parties, request the Executive Secretary to arrange a special consultative meeting to discuss the objections raised. Such a request shall be made not later than the end of 24 weeks from the date on which the Executive Secretary circulated the notification to the Contracting Parties.

6. The Executive Secretary shall arrange for such a special consultative meeting to be held within 6 weeks of the request for it, unless the Contracting Party considering the issue of a permit agrees to an extension. The meeting shall be open to all Contracting Parties, the operator of the installation in question and all observers to the Commission. The meeting shall focus on the information provided in accordance with paragraphs 1 and 3 and during the consultations under paragraph 4. The chairman of the meeting shall be the Chairman of the Commission or a person appointed by the Chairman of the Commission. Any question about the arrangements for the meeting shall be resolved by the chairman of the meeting.

7. The chairman of the meeting shall prepare a report of the views expressed at the meeting and any conclusions reached. That report shall be sent to all Contracting Parties within two weeks of the meeting.

8. The competent authority of the relevant Contracting Party may take a decision to issue a permit at any time after:

a. the end of 16 weeks from the date of dispatch of the copies under paragraph 2, if there are no objections at the end of that period;
b. the end of 22 weeks from the date of dispatch of the copies under paragraph 2, if any objections have been settled by mutual consultation under paragraph 4;
c. the end of 24 weeks from the date of dispatch of the copies under paragraph 2, if there is no request for a special consultative meeting under paragraph 5;
d. receiving the report of the special consultative meeting from the chairman of that meeting.

9. Before making a decision with regard to any permit under paragraph 3 of this Decision, the competent authority of the relevant Contracting Party shall consider both the views and any conclusions recorded in the report of the special consultative meeting, and any views expressed by Contracting Parties in the course of this procedure.

10. Copies of all the documents which are to be sent to all Contracting Parties in accordance with this procedure shall also be sent to those observers to the Commission who have made a standing request for this to the Executive Secretary.

PERMIT CONDITIONS AND REPORTS

1. Every permit issued in accordance with paragraph 3 of this Decision shall specify the terms and conditions under which the disposal at sea may take place, and shall provide a framework for assessing and ensuring compliance.

2. In particular, every permit shall:
   a. specify the procedures to be adopted for the disposal of the installation;
   b. require independent verification that the condition of the installation before the disposal operation starts is consistent both with the terms of the permit and with the information upon which the assessment of the proposed disposal was based;
   c. specify any management measures that are required to prevent or mitigate adverse consequences of the disposal at sea;
   d. require arrangements to be made, in accordance with any relevant international guidance, for indicating the presence of the installation on nautical charts, for advising mariners and appropriate hydrographic services of the change in the status of the installation, for marking the installation with any necessary aids to navigation and fisheries and for the maintenance of any such aids;
   e. require arrangements to be made for any necessary monitoring of the condition of the installation, of the outcome of any management measures and of the impact of its disposal on the marine environment and for the publication of the results of such monitoring;
   f. specify the responsibility for carrying out any management measures and monitoring activities required and for publishing reports on the results of any such monitoring;
   g. specify the owner of the parts of the installation remaining in the maritime area and the person liable for meeting claims for future damage caused by those parts (if different from the owner) and the arrangements under which such claims can be pursued against the person liable.

3. Every report under paragraph 9 of this Decision shall set out:
   a. the reasons for the decision to issue a permit under paragraph 3;
   b. the extent to which the views recorded in the report of the special consultative meeting under paragraph 7 of Annex 3 to this Decision, or expressed by other Contracting Parties during the procedure under that Annex, were accepted by the competent authority of the relevant Contracting Party;
   c. the permit issued.

4. Every report under paragraph 10 of this Decision shall set out:

   a. the steps by which the disposal at sea was carried out;

   b. any immediate consequences of the disposal at sea which have been observed;

   c. any further information available on how any management measures, monitoring or publication required by the permit will be carried out.

ANNEX C

THE CONTENTS OF A DECOMMISSIONING PROGRAMME

Presentation

The draft programme should be presented in a form that allows ready updating and change. Each draft should be dated, pages should be numbered, and any diagrams, charts etc should be annexed to the main text. The maximum use should be made of tabular presentation. To reduce the burden on industry, DECC invites companies to prepare drafts which are as short as possible, consistent with providing information discussed below proportionate to the project concerned.

Separate programmes should be prepared for pipelines and installations although these can be contained within the same decommissioning document. This is necessary because the Petroleum Act 1998 has the effect of requiring a decommissioning programme in respect of each set of equipment which is the subject of a section 29 notice or series of related section 29 notices. It should be possible to identify the different programmes in order to isolate the liabilities of the different groups of notice holders.

There is further guidance at the end of this Annex on how to structure combined decommissioning documents.

The format and content of the draft programme should, where appropriate, accord with the following guidance:

Format and Content

1. Introduction

A brief introductory paragraph indicating that the decommissioning programme is being submitted for approval in accordance with the requirements of the Petroleum Act 1998. It should also clearly indicate the companies that will be a party to the programme and any differences in ownership status.

2. Executive Summary

A management summary outlining the background to the decommissioning proposals and highlighting the essential features of the proposed method of decommissioning.

3. Background Information

Relevant background information, supported by diagrams, including:

- The relative layout of the facilities to be decommissioned (installations, subsea equipment and pipelines).

- The relative location, type and status of any other adjacent facilities (telephone cables, other pipelines and platforms etc) which would have to be taken into consideration.
- Information on prevailing weather, sea states, currents, seabed conditions, water depths etc.
- Any fishing, shipping and other commercial activity in the area.
- Any other background information relevant to consideration of the draft decommissioning programme.

4. Description of Items to be Decommissioned

A description, inclusive of diagrams, covering:

Installations

- Support structures for fixed and floating installations (type, size, arrangement and weights).
- Topsides for fixed and floating installations (type, size, configuration, equipment and weights).
- A list of all wells (including subsea and satellite wells and whether active, suspended or abandoned).
- Subsea equipment on or in the seabed (size, weight, height above seabed, whether piled or not, type of construction and material, details of interaction between equipment and other uses of the sea, e.g. fishing).
- Offshore loading facilities.
- Any other installed items.

Pipelines, flow lines and umbilicals

- Lengths, diameters, type of construction.
- The extent of burial, trenching and details of any concrete mattresses, grout bags, rock-dump or other materials used to cover the lines.
- Details of any subsea facilities that form part of the pipelines (e.g. PLEM, UTA, riser anchor bases).
- The stability of the pipelines including details of any spanning or exposure (survey data and history to support information given in this section should be included as an annex to the programme).

- Details of interaction between any part of the pipelines and other uses of the sea (e.g. fishing).

Materials on the Seabed

- Drill cuttings (amount, composition, dimensions) or cross-reference the drill cuttings section of the programme if appropriate.

- Debris.

- Any other materials.

In some cases there will be related equipment, usually within the same field, that is not covered by the decommissioning programme. If appropriate this should be listed here for clarity and an explanation given of why it is not part of the programme. The requirement for this will vary with each case and will be established during early discussions with DECC in stage 1 of programme development.

5. Inventory of Materials

For all items described under 4 above, include an inventory listing the amount, type and relative location of all materials including hydrocarbons, sludges, heavy metals, sacrificial anodes and any radioactive material including LSA (Low Specific Activity) scale. Where exact quantities cannot be verified, estimates should be calculated.

6. Removal and Disposal Options

This section will provide a general description of the alternative removal and disposal options for the items described in 4 above. It should include a short list of options and the reasons for rejecting those not short-listed.

Re-use and Phasing

Particular consideration should be given to the possibility for re-use and the potential for the beneficial phasing/integration of decommissioning activity between operators, e.g. within a particular geographic area or specialist type of work, in order to realise any economies of scale that are possible.

Comparative Assessment

If the programme relates to an installation for which the owners are seeking a derogation under paragraph 3 of OSPAR Decision 98/3 then a detailed comparative evaluation of the alternative disposal options must be included in this section. The terms of the evaluation and the information to be included is set out in Annex 2 to the OSPAR Decision. (*See Annex B of these Guidance Notes*). In deciding whether a case has been made out for a derogation DECC will judge the comparative assessment against the criteria and approach set out in *Annex A.*

Similarly, a programme for pipelines, should also include a comparative assessment. In order to arrive at the best decommissioning option, the assessment should examine and compare each option on the basis of: complexity and associated technical risk; risks to personnel; environmental impact; effect on safety of navigation and other uses of the sea; and economics. *(See Section 10)*

7. <u>Selected Removal and Disposal Option</u>

This section should describe the proposed decommissioning option. It should include:

- The removal and disposal option, describing the removal method and the disposal route, recognising any potential transfrontier shipment of waste issues.

- An indication of how the principles of the waste hierarchy will be met, including the extent to which the installation or any part of it, including the topsides and the materials contained within it, will be re-used, recycled or scrapped.

- Details of any cleaning or removal of waste materials, including cleaning methods; cleaning agents and disposal of residues.

- A clear outline of how the disposal of any radioactive material, including LSA scale, will be addressed. If appropriate this should include an indication of whether the potential disposal route requires authorisation under the Radioactive Substances Act 1993 and whether the appropriate authorisation is already in place.

- Details of any materials and remains on the seabed after decommissioning.

- Water clearances above any remains.

- Predicted degradation, movement and stability of any remains.

8. <u>Wells</u>

The abandonment of wells is regulated under the model clauses incorporated in individual licences. In addition, section 75 of the Energy Act 2008 gives the Secretary of State power to require information and, specific action to be taken in relation to well abandonment. This action includes the provision of financial security for the purpose of ensuring that a person will be capable of plugging and abandoning a well when required to do so by the terms of the licence. However, long-term obligations in respect of abandoned wells will be subject to Part IV of the Petroleum Act. The decommissioning programme should therefore contain:

- A listing of all active, suspended and previously abandoned wells relating to the installation. It should be possible from this list to identify each individual well. If this information is already included in section 4 (description of items to be decommissioned) it does not need to be repeated but can simply be cross referenced.

- A summary of the methods used or proposed to be used to abandon the wells. This requirement will be met by confirmation that abandonment has been carried out in accordance with the Oil & Gas UK Guidelines for the Suspension and Abandonment of Wells and that a PON5 will be submitted in support of any works that are to be carried out. *Guidelines on well abandonment are available from http://www.oilandgasuk.co.uk/ and further details regarding the PON5 process can be found at: https://www.og.decc.gov.uk/regulation/pons/pon_05.htm*.

9. Drill Cuttings

This section should describe actions taken to implement the requirements of OSPAR Recommendation 2006/5 *(see Section 11 and Annex I)*. If it has been agreed that Stage 2 of the management regime set out in the Recommendation is necessary and can be initiated at the time of decommissioning, the programme should contain the outcomes including the required comparative assessment, the conclusions from it and the proposed action to deal with the cuttings pile. Where initial screening assessed the accumulations as below the Stage 1 threshold, details regarding the cuttings pile should still be included in the programme. This is particularly important where extrapolation of data for other piles was the basis for the initial assessment. At the time of decommissioning survey data should be presented to support the initial findings and, where either threshold in Recommendation 2006/5 is exceeded, a comparative assessment and proposed action to deal with the pile, in line with Stage 2 of the Recommendation's management regime, should be conducted.

10. Environmental Impact Assessment

This section should include an Environmental Impact Assessment (EIA) of the selected decommissioning option. It should not be necessary to repeat information that is presented elsewhere in the decommissioning programme but an assessment of the potential effects of the project on the environment and climate change must be undertaken and the measures envisaged to avoid, reduce and, if possible remedy any significant adverse effects indicated. The EIA should include the following:

- All potential impacts on the marine environment, including exposure of biota to contaminants associated with the installation, other biological impacts arising from physical effects, conflicts with the conservation of species, with the protection of their habitats, or with mariculture, and interference with other legitimate uses of the sea.

- All potential impacts on other environmental compartments, including emissions to the atmosphere, leaching to groundwater, discharges to surface fresh water and effects on the soil.

- Consumption of natural resources and energy associated with re-use and recycling.
- Other consequential effects on the physical environment which may be expected to result from the option.
- Potential impacts on amenities, the activities of communities and on future uses of the environment.

EU Habitats and Birds Directive

It is expected that a properly conducted EIA would:

- Identify any habitats or species listed in Annex I of the Habitats and Birds Directives and covered by the Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001;
- Determine the likely impacts on them of the decommissioning activities and propose any suitable mitigation;
- Propose an appropriate management system.

These findings should be included in the decommissioning programme as part of the EIA and will provide the information for DECC as competent authority for the Habitats Regulations offshore, to undertake an appropriate assessment if this is required.

For proposed activities within 40 km of the coast the possibility of the operations, or an accident or incident during the operations, impacting protected coastal habitats and species must also be considered. The EIA must also identify and address these risks and provide sufficient information to allow an appropriate assessment to be prepared where necessary.

Within any assessment all future requirements to undertake post-decommissioning surveys and potential remedial works must be clear. Where these activities could impact protected habitats or species, this must be addressed in the EIA and a further appropriate assessment may be required prior to the post-decommissioning activities.

Further Natura 2000 sites, e.g. a Special Area of Conservation (SAC) or Special Protection Areas (SPA), are likely to be identified and other conservation areas may be designated in areas where at the time of decommissioning no known sites were present. It is the responsibility of the Operator to ensure that all future activities meet the requirements of the Regulations and they should approach DECC prior to any activities being undertaken.

Where activities require formal environmental approval, e.g. a chemical or oil discharge permit, there will normally be a recommended 28 day notification period and a requirement to undertake an appropriate assessment could add weeks to the approval process.

Use of Explosives

As part of the EIA it will be necessary to assess the potential impacts of the use of any explosives on marine life in particular marine mammals. The use of explosives can be permitted where this is shown to be the best practicable environmental option. The impact assessment should include a description to justify the necessity to use explosives including the alternatives which have been considered; the potential impacts of the explosive use and the proposed mitigation strategy. Suggestions for appropriate mitigation are included within the JNCC Guidelines for minimising acoustic disturbance to marine mammals whilst using explosives, available from the JNCC (http://www.jncc.gov.uk/default.aspx?page=4900).

11. Interested Party Consultations

A description is required of the consultation process employed, including a summary of the statutory consultations with interested parties and the extent to which they have been taken into account in the programme. Relevant correspondence should be annexed to the programme. In those cases where it has been necessary to conduct a wide ranging public consultation/dialogue process, including any informal consultations with OSPAR Contracting Parties, details of the approach taken and the outcome of the process should be included.

12. Costs

There should be an overall cost estimate in £ sterling of the preferred decommissioning option and an indication of the basis on which the estimate is made. The estimate should be broken down to reflect the activities in the 'Element Level' of the Oil & Gas UK Decommissioning Cost Estimating Guidelines. These guidelines have been developed in workgroup 4 of the Brownfields decommissioning initiative with the aim of establishing a common approach to decommissioning costs. The guidelines are available on Oil & Gas UK's website using the following link: http://www.oilandgasuk.co.uk/

If it is anticipated the decommissioning work will span a number of years, expenditure should be split by year. In cases with more than one platform, expenditure should be split by platform.

It is recognised that in some cases accurate cost data and confirmation of the final decommissioning option are dependent on the outcome of a commercial tendering process. Operators should discuss any sensitivities about cost data with DECC.

13. Schedule

Details of the decommissioning time scale for the proposed option, including a schedule showing the dates at which the various stages of the decommissioning are expected to start and finish, should be included.

14. Project Management and Verification

Information on how the Operator will manage the implementation of the decommissioning programme and provide verification to DECC concerning progress and compliance. This should include a commitment to submit a report, detailing how the programme was carried out, within four months of completion of the decommissioning work, including debris clearance and post-decommissioning surveys *(see Section 13)*.

15. Debris Clearance

This section should include proposals for identification and removal of seabed debris following decommissioning works. As a minimum the area covered for debris clearance should include a 500m radius around any installation and a 200m corridor along the length of any pipelines. Identification of debris would normally be conducted by side scan sonar with an ROV deployed to investigate and recover any potential hazards located. Following this work, verification of seabed clearance by an independent organisation will normally be required. This requirement will depend on the circumstances of the case and will be decided in discussion with DECC.

16. Post-Decommissioning Monitoring and Maintenance

Proposals covering the post-decommissioning phase:

- Seabed sampling surveys to monitor levels of hydrocarbons, heavy metals and other contaminants in sediments and biota. There should be a commitment to submit the results of surveys to DECC. On completion of the last intended survey, the requirement for further work will depend on the results and will be agreed in discussion with DECC.

- Inspection and maintenance where remains are to be left in place. There should be a commitment to report the outcome of this work to DECC. If a long-term schedule of inspection and maintenance is not given, there should at least be a commitment to conduct further work in response to the results of the initial inspection and in consultation with DECC.

17. Supporting Studies

Where supporting studies have been undertaken they should be listed within the programme and should be available to enquirers on request.

18. Structure of Combined Decommissioning Programmes

Where it has been agreed in discussion with DECC that it would be beneficial to include more than one programme within a decommissioning document, it should take account of the following:

- In the Introduction provide a clear statement that the document contains a separate programme for each set of associated notices served under section 29 of the Petroleum Act 1998.

- The Introduction should identify the obligations associated with each programme. The programmes should be listed indicating which installations or pipelines are covered by each one and what companies will be a party to which programme. To further identify the obligations it is useful to include a table indicating which sections and subsections of the document refer to each separate programme.

- Clear identification of costs and show which programme they refer to.

- The responsibility for any survey and monitoring requirements should be clearly allocated to individual programmes or clearly shared by all.

- A timetable that shows the work for all programmes.

There is no need to duplicate sections. If a section contains information relating to separate programmes, subsections can be used to highlight the allocation e.g. costs. In most cases the need to include more than one programme in a decommissioning document will arise in the context of pipelines. As indicated above decommissioning proposals for pipelines should be contained within a separate programme in order to be able to clearly identify the specific decommissioning obligations that apply to the lines, which may have different owners from the installations.

ANNEX D

OTHER LEGISLATION, REGULATIONS AND CONTROLS

1. The following provides an indication of the legislation, in addition to the Petroleum Act 1998 and the environmental regulations referenced in section 12, that may apply to decommissioning activity. The table at the end of this Annex summarises the activities involved and the permits or authorisations likely to be required. The list is not intended to be exhaustive as individual cases will differ. Operators should discuss their decommissioning proposals with the relevant Departments and Agencies responsible for the legislation.

The Coast Protection Act 1949

2. This Act, as extended by the Continental Shelf Act 1964, contains provisions for the safety of navigation. Before an installation or pipeline can be placed on the UKCS the consent of the Secretary of State for Energy and Climate Change is required under section 34, Part II of the Act. The standard form of consent will normally be subject to the standard marking conditions. If variations are proposed or required in a particular case, special conditions may be added. If a facility "falls into disuse" there is a requirement for operators to take steps for the purpose of preventing obstruction or danger to navigation as directed by the Secretary of State. The satisfactory completion of a decommissioning programme approved under the Petroleum Act 1998 should satisfy the requirements of the Coast Protection Act.

Food and Environment Protection Act 1985

3. A licence is required, under Part II of the Food and Environment Protection Act 1985 (FEPA) as amended, for the deposit of substances or articles within United Kingdom Continental Shelf, either in the sea or under the seabed unless exempt under the Deposits in the Sea (Exemptions) Order 1985. Schedules 14, 15 and 16 specifically exempt many oil and gas exploration and production activities as these are controlled by DECC's own legislation.

4. For the deposit of any substances or articles in respect of oil and gas activities which are not exempt (such as deposits made in connection with offshore decommissioning activity) a FEPA licence may be required. For the waters adjacent to England and Wales, FEPA is administered by the Marine Management Organisation (MMO) of the Department for Environment, Food and Rural Affairs, and in waters adjacent to Northern Ireland by the Northern Ireland Environment Agency of the Department of the Environment (Northern Ireland). For such deposits in waters adjacent to Scotland, DECC is the responsible licensing authority, except in relation to activities in certain "controlled waters", where the licensing authority is the Scottish Government – Marine Scotland. These "controlled waters" extend to 3 nautical miles from a defined coastal baseline within the meaning of section 30A(1) of the Control of Pollution Act 1974.

The Environmental Permitting (England and Wales) Regulations 2007, Pollution Prevention and Control Act 1999 and Waste Management Licensing Regulations 1994,

5. In England and Wales, the Environmental Permitting (England and Wales) Regulations 2007 (EPR) cover facilities previously regulated under the Pollution Prevention and Control Regulations (PPC)_ and the Waste Management Licensing Regulations 1994 (WML). PPC and WML continue to pertain to Scotland.

6. EPR/PPC provide robust legislative systems to regulate industrial processes involved in the treatment of certain prescribed wastes. These include the metal processing industry, which may recover metallic items from a decommissioning operation, and the incineration of wastes. Anyone carrying out these processes must do so in compliance with an environmental permit/authorisation that is designed to prevent pollution of the environment or harm to human health. These are the responsibility of the Scottish Environment Protection Agency (SEPA) in Scotland and the Environment Agency (EA) in England and Wales.

7. EPR/WML are the main means by which the requirements of the EC Framework Directive on Waste is transposed into domestic law. Anyone who deposits, recovers or disposes of controlled waste must do so in compliance with the conditions of an environmental permit/waste management licence, or within the terms of an exemption from the need for a permit/licensing, and in a way which does not cause pollution of the environment or harm to human health.

8. The term "controlled waste" means household, commercial and industrial waste. Whether or not a substance is waste must be determined on the facts of the case, and advice should be sought from the Agencies. (Guidance on the definition of waste is contained in DOE Circular 11/94 which is currently being updated.)

9. In determining an application for a permit/licence, the Agencies must be satisfied that the activities will not cause harm to human health or pollute the environment and the site is managed by a fit and proper person.

The Environmental Protection Act 1990

10. In addition to the above, persons concerned with controlled waste are under a duty of care, under the EPA1990, to ensure that the waste is managed properly, recovered or disposed of safely, does not cause harm to human health or pollution of the environment and is only transferred to someone who is authorised to receive it. This duty applies to any person who produces, imports, carries, keeps, treats or disposes of controlled waste or as a broker has control of such waste. Breach of the duty of care is an offence, with a penalty of up to £5000 on summary conviction or an unlimited fine on conviction on indictment. As part of DEFRA's simplification of the regulatory controls for handling, transferring and transporting waste they are currently considering extending the

duty of care under the EPA to include those involved in transfrontier shipment of waste.

11. The system for the registration of waste carriers is set up under the Control of Pollution (Amendment) Act 1989 and the Controlled Waste (Registration of Carriers and Seizure of Vehicles) Regulations 1991 (as amended). Those who, in the course of their business or in any other way for profit, transport controlled waste within Great Britain must register with the Environment Agency as carriers of controlled waste.

Special Waste Regulations 1996 – Special Waste Amendment (Scotland) Regulations 2004 / Hazardous Waste (England and Wales) Regulations 2005

12. Depending on its nature and composition waste may be defined as special waste (in Scotland) / hazardous waste (in England and Wales) within the UK. Special/hazardous wastes are those that are potentially the most difficult and dangerous and listed on the European Union's Hazardous Waste List. The Regulations require all movement of special/hazardous waste to be tracked by way of a consignment note system.

Transfrontier Shipment of Waste Regulations 2007

13. The international movement of waste is controlled by means of Council Regulation No 1013/2006/EC on shipments of waste (the "WSR"). The Transfrontier Shipment of Waste Regulations 2007 gives effect to certain aspects of the WSR into UK law, nominate the competent authorities for the UK and provide them with their respective enforcement powers. The UK Plan for Shipments of Waste sets out Government policy on shipments for disposal. The Regulations are enforced by the EA (England and Wales), SEPA (Scotland) and NI Environment Agency (Northern Ireland). The regulations apply to decommissioned offshore installations. The Secretary of State is the competent authority for the offshore area. Operators should consult the appropriate Agency when considering decommissioning activities that involve transboundary movements of waste.

Radioactive Substances Act 1993

14. Anyone who receives radioactive sources or radioactive waste for disposal is subject to the requirements of the Radioactive Substances Act 1993 (RSA 93). Under this Act they must have an authorisation from the appropriate regulatory body (EA in England & Wales; SEPA in Scotland) for the accumulation, storage or disposal of radioactive waste or be able to demonstrate compliance with the conditions contained in specific exemption orders. The Act does apply to offshore installations and the preparation of a decommissioning programme should identify whether the selected disposal route requires such an authorisation and that the selected facility has one. It is likely that new disposal routes will require an application for authorisations.

Transfrontier Shipment of Radioactive Waste and Spent Fuel Regulations 2008

15. The Transfrontier Shipment of Radioactive Waste and Spent Fuel Regulations 2008 (TFSRWR 2008) transpose Council Directive 2006/117/Euratom on the supervision and control of shipments of radioactive waste and spent fuel. TFSRWR 2008 make it an offence to ship radioactive waste or spent fuel into or out of the UK unless authorised by the appropriate authority. The new regulations came into force on 25 December 2008 and are administered by the EA in England and Wales, SEPA in Scotland and the Chief Inspector in Northern Ireland. They replace and revoke the previous UK regulatory regime (The Transfrontier Shipment of Radioactive Waste Regulations 1993) and some transfers of radioactive waste across international boundaries which were previously regulated are now exempted. TFSRWR 2008 do not apply to the shipment of naturally occurring radioactive material (NORM) or the shipment of disused sources to a supplier or manufacturer of radioactive sources or to a recognised installation. For the purposes of the regulations a disused source means a sealed source which is no longer used or intended to be used for the practice for which authorisation was granted and a recognised installation means a facility located in the territory of the country authorised by the competent authorities of that country for the long-term storage or disposal of sealed sources or an installation authorised for the interim storage of sealed sources.

Dangerous Substances in Harbour Areas Regulations 1987

16. The carriage, loading, unloading and storage of all classes of dangerous substances in port areas are controlled under the Dangerous Substances in Harbour Areas Regulations 1987 (and amendments) and the Waste Management Licensing Regulations 1994.

Water Resources Act 1991 and Water Environment and Water Services (Scotland) Act 2003

17. Underpinning these instructions, it is an offence in England and Wales under the Water Resources Act 1991 to cause or knowingly permit any poisonous noxious or polluting matter to enter any "controlled" waters. In Scotland, the Water Environment and Water Services (Scotland) Act 2003 (WEWS), introduces regulatory controls over activities in order to protect and improve Scotland's water environment. It is an offence for a person to carry on, or cause or permit others to carry on, any controlled activity unless authorised by the Controlled Activity Regulations 2005 (as amended). Controlled waters extend to three miles from a defined baseline in England and Wales, as detailed in the Water Resources Act 1991. Coastal waters extend to three miles from a defined baseline in Scotland, as detailed in the WEWS. Other named activities under Crown control are outlined in the Continental Shelf Act 1964.

Health and Safety at Work etc Act 1974

18. Where installations, pipelines and/or waste are brought onshore for disposal, the operations will be subject to the provisions of the Health and Safety

at Work etc Act 1974 and appropriate regulations made under that Act. Further details can be obtained from the Health and Safety Executive (HSE).

19. HSE's role in decommissioning stems from the Offshore Safety Act 1992 which extends the application of Part I of the Health and Safety at Work etc Act 1974 to include offshore health and safety. It also allows offshore regulations to be made. Offshore regulations include specific requirements to secure the safe decommissioning and dismantlement of offshore installations and pipelines.

20. The Offshore Installations (Safety Case) Regulations 2005 (OSCR2005) came into force in April 2006, replacing the 1992 Safety Case Regulations. The new regulations require acceptance by HSE of a safety case for the dismantlement of a fixed installation. OSCR2005 are aimed at simplifying procedures as well as bringing OSCR more in line with other supporting offshore legislation. The new regulations can be found on the OPSI website at: http://www.opsi.gov.uk/si/si2005/20053117.htm

21. OSCR2005 requires a safety case to be submitted at least 3 months before the commencement of dismantling. In accepting a safety case under OSCR2005, HSE will wish to be satisfied that there is an effective safety management system (SMS) in place. The SMS should ensure that hazards with potential to cause a major accident are identified, that risks are adequately controlled and that the organisational arrangements in place will enable the duty holder to comply with relevant statutory provisions. The rigorousness of the SMS will be especially significant during decommissioning in order to cater for factors such as reduced personnel on board or contractor personnel new to the installation.

22. A range of other statutory health and safety provisions will apply during decommissioning, including regulation 10 of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 which requires the decommissioning and dismantlement of an installation to be done safely so as to maintain its integrity during work activities.

23. The Pipelines Safety Regulations 1996 contain requirements that pipelines are decommissioned safely either by dismantlement and removal or by being left in a safe condition, and for notification of decommissioning works at least 3 months prior to commencement.

24. Inspectors from HSE's Hazardous Installations Directorate (Offshore Division) enforce offshore health and safety legislation. Pipelines safety legislation is enforced by HSE's Hazardous Installations Directorate (Specialised Industries Division). Application of the Health and Safety at Work etc Act 1974, and the regulations made under the Act, to any activities associated with decommissioning which are carried out onshore would most likely be dealt with by inspectors from HSE's Field Operations Division.

25. All works at a well are subject to the general requirements of the Health and Safety at Work Act etc 1974. In addition, there are specific regulatory requirements which apply to wells and well integrity. Wells connected to an

installation form part of that installation, and the content of the safety case must include particulars of the plant and arrangements for the control of operations on a well, including control of pressure and the prevention of the release of hazardous substances. Operations to re-enter and abandon wells using a mobile installation or vessel must be notified to HSE 21 days in advance. Duties set out in the Offshore Installations and Wells (Design and Construction etc) Regulations 1996 also cover the abandonment of wells. These require that wells are suspended and abandoned in a way that ensures there can be no unplanned escape of fluids from a well and that the risks to the health and safety of persons from the well, anything in it, or the strata to which it is connected, are as low as reasonably practicable.

Export Controls

26. The export of oil and gas installations for re-use outside of the UKCS may be subject to United Kingdom export controls. The Export Control Directorate of the Department for Business, Innovation and Skills (BIS) is the competent authority in this matter.

27. An export licence is unlikely to be required unless the goods are listed in Schedule 1 to the Export of Goods, Transfer of Technology and Provision of Technical Assistance (Control) Order 2003 (EGTTPTA(C)O 2003, as amended: Part I (UK Military List) and Part II (UK Explosive – Related List) or there are any goods on the platform that could be considered to be 'dual-use' as defined in Schedule 2 to the 2003 Order (UK Dual-Use List) or in Council Regulation (EC) No. 1334/2000, as amended (EU Dual-Use List).

28. A number of Open General Export Licences (OGELs) are also issued and may be applicable as they cover various goods and destinations. OGELs are valid for any exporter to use providing they can satisfy the conditions and restrictions as specified on each licence.

29. BIS Export Control Directorate website http://www.bis.gov.uk/exportcontrol provides information relating to the lists of items considered to be subject to control (dual-use and military) and other general information on export controls including copies of all current Open General Export Licences.

SUMMARY OF MAIN ACTIVITIES REQUIRING APPROVAL:

ACTIVITY	AUTHORITY	PERMIT/CONSENT	REMARKS
Cessation of Production	DECC		Handled through Field Reports and separate COP Document
Venting/Flaring	DECC	Venting/Flaring consent under the Energy Act 1976	
Safety case	HSE	Acceptance under the Offshore Installations (Safety Case) Regulations 2005	OSCR2005 came into force in April 2006
Well abandonment	DECC, HSE	PON5	See DECC's Oil & Gas Website
Cleaning, discharges, emissions	DECC, EA/SEPA (depending on location)	PON15D, PON15C and/or PON15E (Chemicals) Permit under the OPPC Regs 2005 (Oil) Note:decommissioning activity may be covered by existing operational permits	See DECC's Oil & Gas Website
Oil Spill Planning	DECC	Oil Pollution Emergency Plan required under Merchant Shipping (Oil Pollution Preparedness, Response and Cooperation Convention) Regulations 1998	Decommissioning may be incorporated into existing field OPEP
Explosives use	DECC	Assessment under Habitats Regulations (as amended) 2001	Agree with DECC and apply JNCC Guidelines

ACTIVITY	AUTHORITY	CONSENT/PERMIT	REMARKS
Seabed deposits	DECC, DEFRA, Devolved Authorities (depending on location)	Licence under FEPA 1985 DEPCON under Pipeline Works Authorisation	Deposits on decommissioned pipelines subject to FEPA. Deposits on pipelines held under IPR likely to be via DEPCON.
Waste Handling	EA/SEPA	Duty of care under Environmental Protection Act 1990 Licence under Waste Management Licensing Regulations 1994/Environmental Permit issued under Environmental Permitting (England and Wales) Regulations 2007 Notification under Special Waste Regulations 1996 and Special Waste Amendment (Scotland) Regulations 2004 / Hazardous Waste (England and Wales) Regulations 2005 Authorisation under Radioactive Substances Act 1993	Proposals should be discussed at an early stage with the relevant Agency

ACTIVITY	AUTHORITY	CONSENT/PERMIT	REMARKS
Waste Shipment (into and out of the EU)	EA/SEPA	Authorisation under the Transfrontier Shipment of Waste Regulations 2007	Authorisation also required from the receiving country. Authorisation also for any waste being returned to the country of origin.
Marine activities	DECC,DfT,Hydrog,HSE, MCA, SFF, NFFO	Various notifications required for diving activities, vessel use, towing activities etc	Discuss with relevant Departments, Agencies or Bodies
Safety Zones	HSE, Hydrog, DfT	Notification upon removal of facilities	Under Petroleum Act 1987, SZ will automatically cease if installation no longer projects above the surface of the sea. SZ's made by statutory order will remain unless removed by order.
Equipment and materials brought ashore	HM Revenue & Customs	Duties and VAT may apply to certain items	Discuss with HMRC

ACTIVITY	AUTHORITY	CONSENT/PERMIT	REMARKS
Export of installations and equipment Export and import	BIS DEFRA	An export licence may be required in certain circumstances under the Export of Goods, Transfer of Technology and Provision of Technical Assistance (Control) Order 2003 A certificate may be required under the Convention on International Trade in Endangered Species (CITES)	Consult BIS Export Control Directorate If the coral, *Lophelia pertusa*, is present on an installation located outside of territorial waters that is being transported to the UK or elsewhere, a CITES certificate will be required from Defra.

ANNEX E

ROLE OF OTHER GOVERNMENT DEPARTMENTS

Department for Environment, Food and Rural Affairs (Defra)

1. Defra is responsible for co-ordinating Government policy on the marine environment. It therefore has an interest in all general questions which arise in respect of offshore oil and gas activity and the marine environment. Defra is also responsible for Government policy on waste and sponsors the Environment Agency. Defra is specifically responsible for the development and implementation of domestic and international policies to protect fisheries and the marine environment from the deposit of waste and other materials at sea. Defra leads for the UK on the global London Convention 1972 which deals with dumping at sea and also leads for the UK on the OSPAR Convention for the protection of the North East Atlantic which not only covers dumping issues but also the prevention and elimination of pollution from offshore installations. An extensive programme of aquatic environmental monitoring is carried out on behalf of the Department.

2. Defra is responsible for the Food and Environment Protection Act (Part II) 1985 (FEPA) as amended. Part II of the Act covers the deposit of substances or articles in the sea or under the seabed within UK waters or UK controlled waters. Anyone wishing to undertake activities involving the deposit of materials at sea, in waters adjacent to England and Wales, is advised to check the following web page http://www.marinemanagement.org.uk/environment/index.htm to confirm if a licence is required or if the activities are exempt under the Deposits in the Sea (Exemptions) Order 1985 and covered by legislation. In assessing whether a licence can be issued under FEPA, Defra will consider whether the deposits will adversely affect the marine environment, the living resources which it supports or human health. Regard is also taken of operations which may interfere with legitimate uses of the sea and to the practical availability of alternative methods of dealing with any waste material it is proposed to dispose of at sea.

The Scottish Government – Marine Scotland (SG-MS)

3. SG-MS, which has a similar role to Defra, is responsible, as licensing authority in Scotland, for issuing licences under Part II of the Food and Environment Protection Act 1985 as amended, for all disposal activities, except after 1 July 1999, those relating to oil and gas exploration and exploitation and operations falling within the subject matter of Part VI of the Merchant Shipping Act 1995. Anyone wishing to undertake activities involving the deposits of substances or articles at sea in waters adjacent to Scotland is advised to check with SG-MS which undertakes the licensing function on behalf of the Scottish Ministers. SG-MS will confirm if a licence is required or if the activities are exempt under the Deposits in the Sea (Exemptions) Order 1985 (as amended).

4. Section D2 of Schedule 5 to the Scotland Act 1998 reserves oil and gas exploration and exploitation to Westminster including, in this regard, the subject

matter of Part II of FEPA, but only in relation to activities outside controlled waters (within the meaning of section 30A(1) of the Control of Pollution Act 1974). Ministers have agreed that the licensing authority for such activities will be DECC.

5. SG-MS, also conducts an extensive marine environment monitoring programme in waters adjacent to Scotland.

Department for Transport (DfT)

6. The Ports Division of DfT is concerned with ensuring safety of navigation and DECC on their behalf regulates the placing of offshore installations and pipelines to this end. Consent is required for placing on the UK Continental Shelf installations which may obstruct or endanger navigation.

Maritime and Coastguard Agency (MCA)

7. The MCA is responsible for implementing the Government's strategy for marine safety and the prevention of pollution from ships, as developed by DfT's Shipping and Ports Directorate in consultation with the Agency. The overall aim of the MCA is to develop, promote and enforce high standards of marine safety and to minimise the risk of pollution of the marine environment from ships. Prior to granting consent for the placing of offshore installations and other works in tidal waters, DfT's Ports Division consult the MCA for their views on the impact of such activities on navigational safety.

8. The Agency is also responsible for the management of the Government's Civil Hydrographic Programme and works closely with the Royal Navy, the Ministry of Defence and the UK Hydrographic Office.

Department of the Environment for Northern Ireland (DOE NI)

9. The Industrial Pollution and Radiochemical Inspectorate (IPRI) is part of the Northern Ireland Environment Agency, and is responsible for the enforcement of the Industrial Pollution Control (NI) Order 1997 the Pollution Prevention and Control Regulations (NI) 2003 and the Radioactive Substances Act 1993.

10. DOE NI is also responsible for co-ordinating policy within Northern Ireland in respect of pollution of the marine environment and complying with the requirements of the OSPAR Convention and other international obligations.

The Joint Nature Conservation Committee (JNCC), Natural England (NE), Scottish Natural Heritage (SNH), the Countryside Council for Wales (CCW) and the Council for Nature Conservation and the Countryside (CNCC)

11. The JNCC has expertise for providing nature conservation advice on matters relating to the offshore oil and gas industry and is the primary point of contact for nature conservation advice on decommissioning programmes. NE, SNH, CCW and CNCC are responsible for providing similar advice on

decommissioning programmes within 12 miles of shore or on projects that have the potential to impact their respective coastal areas.

Scottish Environment Protection Agency (SEPA)

12. SEPA is responsible for the enforcement of pollution legislation in Scotland. This legislation regulates: discharges from prescribed processes under Part I of the Environment Protection Act 1990 (EPA 1990), to be progressively replaced by the requirements of the Pollution Prevention and Control Act 1999 (PPC 1999); the regulation of waste management regime under Part II of EPA 1990 and the waste management activities prescribed under PPC 1999; the keeping and use of radioactive materials and the disposal and accumulation of radioactive waste under the Radioactive Substances Act 1993; and the licensing of a controlled activity in accordance with the Water Environment (Controlled Activities) (Scotland) Regulations 2005 (to protect the water environment). The Radioactive Substances Act 1993 applies to installations operating in Scottish waters and the associated infrastructure. SEPA was created by the Environment Act 1995.

The Environment Agency (EA)

13. The EA regulates a range of activities including those carried out under the Environment Permitting (England and Wales) Regulations 2007 which covers facilities previously regulated under the Pollution Prevention and Control Regulations and the Waste Management Licensing Regulations 1994. Amongst many other things, the EA is also responsible for water protection; managing hazardous wastes; the export of wastes and the use, accumulation and disposal of radioactive materials.

Health and Safety Executive (HSE)

14. HSE's role in decommissioning stems from the Offshore Safety Act 1992 which extends the application of Part I of the Health and Safety at Work etc Act 1974 to include offshore health and safety. It also allows offshore regulations to be made. Offshore regulations include specific requirements to secure the safe dismantling, removal and disposal of offshore installations and pipelines. *HSE's role in the decommissioning process and the key health and safety legislation applying is described in Annex D to this guidance*. Health and safety legislation will continue to apply to any installations left in situ after decommissioning. In particular, duty holders will need to ensure the integrity of the installation and the safety of personnel working on it. It should be noted that the duty holder under offshore health and safety legislation may not be the same as those parties with the duty to carry out a decommissioning programme under the Petroleum Act 1998.

15. The Pipelines Safety Regulations 1996 contains requirements for the safe decommissioning of, and notification to, HSE at least 3 months prior to commencement of pipeline decommissioning works.

16. Activities associated with decommissioning which are carried out onshore will be subject to the provisions of the Health and Safety at Work etc Act 1974 and appropriate regulations made under that Act.

Ministry of Defence (MOD)

17. The MOD's UK Hydrographic Office is responsible for maintaining Admiralty Charts on which installations and pipelines are marked. The charts are supported by a range of Notices to Mariners, in both written and other media. Consents from DfT will specify that Notices are issued at the Operator's expense where activity at an installation has implications for navigation around it.

18. The MOD's Directorate of Safety, Environment and Fire Policy is concerned with the impact of decommissioning on defence operations.

HM Treasury/HM Revenue & Customs

19. HM Treasury and HM Revenue & Customs have an interest in the efficient use of resources in decommissioning and in the impact and yield of North Sea taxation.

The Crown Estate

20. The Crown Estate Commissioners have statutory responsibility for management of the Crown's proprietary interests offshore; these include nearly all of the UK seabed to the territorial limit (12 miles) and exploitation rights on the Continental Shelf (excluding hydrocarbons) under the Continental Shelf Act 1964.

21. The rights to oil and gas underneath the territorial sea and the UK Continental Shelf are vested in the Crown under the Petroleum Act 1998 and are managed by DECC. However, The Crown Estate's consent as landowner is required for all oil and gas pipelines that cross the seabed within 12 nautical miles of the UK coastline. This includes the granting of a lease under which a rental payment will apply based on the size of the pipeline. Notice terminating the rent may be given by the operating company upon completion of decommissioning works.

ANNEX F

DECOMMISSIONING LIABILITIES

Introduction

1. This annex sets out DECC's policy for ensuring that the costs associated with decommissioning offshore oil and gas installations and pipelines on the UK Continental Shelf (UKCS) are met by the companies which own them, or have had an interest in them or in the relevant licences since the serving of the first notice for the facilities.

Guiding Principles

2. In recent years there has been significant trading of UKCS oil and gas assets from large companies to smaller ones. Ministers welcome this development as they have agreed that entrepreneurial activity on the UKCS should be encouraged and that a free trade in mature offshore oil and gas assets and reduced cost burden can help to extend field life and maximise economic recovery. However, at the same time Government has a responsibility to ensure that the taxpayer is not exposed to the risk of default in meeting the costs associated with decommissioning, which could be substantial. The two aims must be carefully balanced.

3. The risk to the Government is that, in relation to any particular field, the participating companies at the time of decommissioning will not have sufficient assets to pay for the work. Or that, although such companies have access to sufficient assets, those assets are outside UK jurisdiction and the powers of enforcement available under the Petroleum Act 1998 (the Act) may not be exercisable so as to ensure that the companies comply with their obligations. In such cases the UK's international obligations might mean that the Government would consider itself obliged to arrange for decommissioning and the cost may then fall on the taxpayer.

4. The mechanism by which the Government balances taxpayer protection and increasing UKCS productivity through licence trading is by the serving and withdrawal of notices under sections 29 and 31(5) of the Act.

Legislative Background

5. Notices under section 29 of the Act may be served on those persons with any interest of a kind set out in section 30(1) of the Act in respect of each individual offshore installation on the UKCS, and in respect of section 30(2) of the Act in respect of each individual offshore pipeline. These section 29 notices require the recipient to submit a decommissioning programme at such time as the Secretary of State may call for it.

6. Withdrawal of a section 29 notice may be granted under section 31(5) of the Act. It should be noted that such a withdrawal is granted at the discretion of the Secretary of State. The circumstances under which withdrawal is considered are detailed below.

7. Further information regarding the serving of notices setting a decommissioning obligation is available in *section 3* of this guidance.

Calculation of Risk and Consideration of Section 29 Notice Release

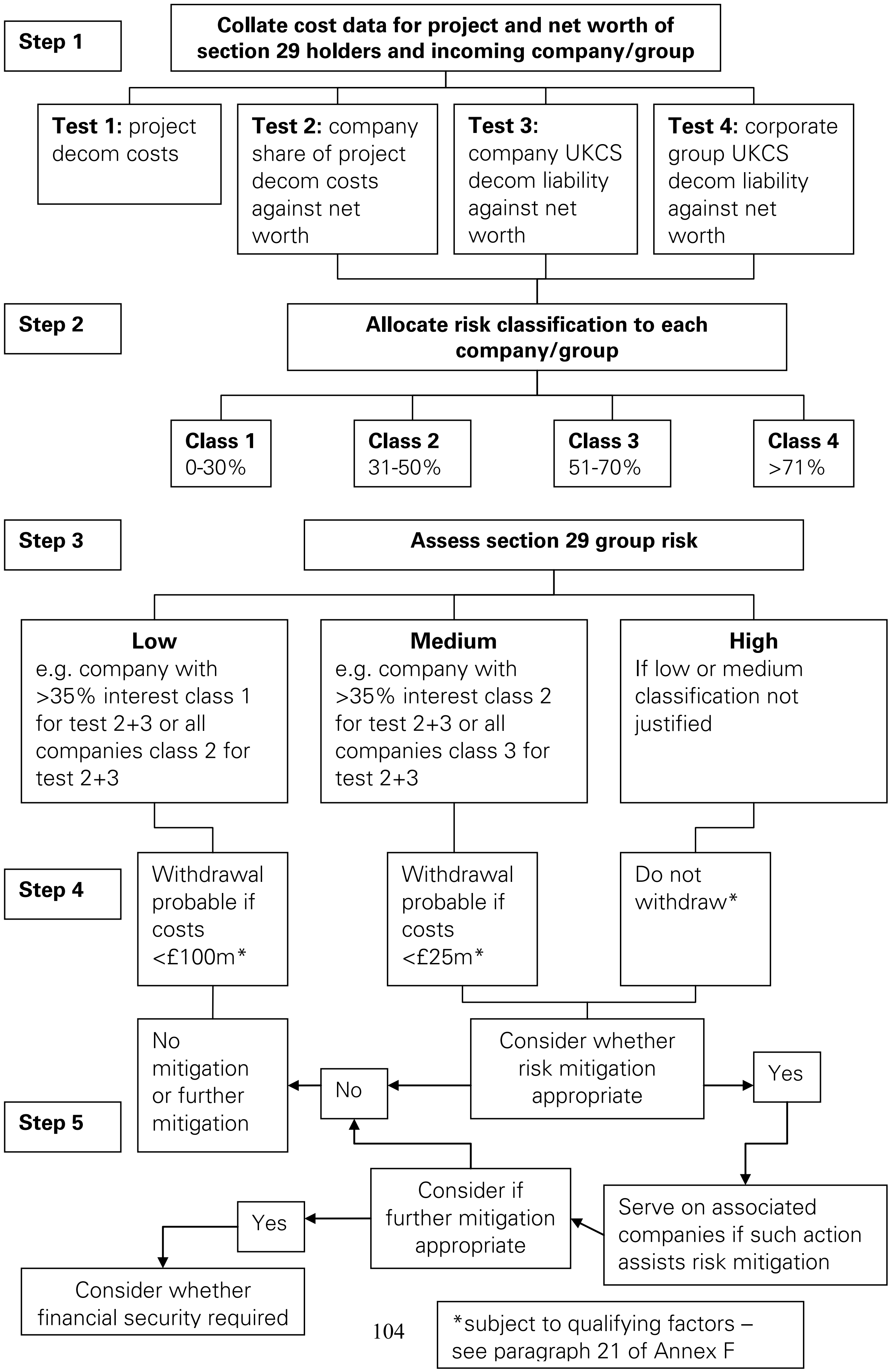
8. When the Licensing Section of DECC's Licensing Exploration and Development Unit agree to an assignment of interests in a licence affecting an approved field, we will serve notices under section 29 of the Act on the buyer (if they do not already have such a notice). We then consider whether the Secretary of State should exercise his discretion under section 31(5), and withdraw the section 29 notice(s) from the selling party.

9. The following assessment is used to calculate the risk associated with the group of section 29 notice holders and whether or not it would be appropriate to withdraw the notice from a selling company. It is also used to review the risk of all section 29 groups on a periodic basis (every 3 to 4 months). It is appropriate that there is an up to date assessment of the overall risk to the taxpayer. Periodic review ensures that updated company accounts and wider changes in a company's and their group's portfolio of assets are taken into account and where necessary mitigation measures instigated. During these reviews particular attention is also given to exited companies that have sold their interest in an asset and not had their section 29 withdrawn to determine if the decision remains appropriate. DECC aims to withdraw as many notices as possible in light of the level of risk.

10. Where a company has requested withdrawal of their section 29 notice following the transfer of their interests in a field, they will be informed whether the Secretary of State will exercise his discretion to withdraw. Where the notice has not been withdrawn at that stage but a periodic review of the risk assessment indicates withdrawal is now appropriate, the relevant companies will be informed. In addition, DECC is always willing to take account of new information or material changes that impact the risk assessment for specific section 29 groups. Companies should contact the Offshore Decommissioning Unit to discuss any relevant updates to their cases. The assessment process is treated as confidential and will only be discussed with the companies concerned.

11. The assessment process is a relatively simple instrument used to assess the risk of all section 29 groups and the mechanistic tests are not the end of the process. Where necessary DECC will review the company's finances in more detail and take account of the prospects for revenues from the relevant fields. In addition, where factors, such as a sudden change in company status, have a material effect on the risk, a detailed review of all the relevant cases will be undertaken. This may alter the initial risk assessment and the resultant need for mitigation measures.

12. The following flowchart outlines the assessment process prior to a more detailed explanation of the steps involved. Examples of how the assessment is used are given at the end of this Annex.


Step 1
Collate cost data for project and net worth of section 29 holders and incoming company/group
Test 1: project decom costs
Test 2: company share of project decom costs against net worth
Test 3: company UKCS decom liability against net worth
Test 4: corporate group UKCS decom liability against net worth
Step 2
Allocate risk classification to each company/group
Class 1 0-30%
Class 2 31-50%
Class 3 51-70%
Class 4 >71%
Step 3
Assess section 29 group risk
Low e.g. company with >35% interest class 1 for test 2+3 or all companies class 2 for test 2+3
Medium e.g. company with >35% interest class 2 for test 2+3 or all companies class 3 for test 2+3
High If low or medium classification not justified
Step 4
Withdrawal probable if costs <£100m*
Withdrawal probable if costs <£25m*
Do not withdraw*
Step 5
No mitigation or further mitigation
No
Consider whether risk mitigation appropriate
Yes
Serve on associated companies if such action assists risk mitigation
Consider if further mitigation appropriate
Yes
Consider whether financial security required
*subject to qualifying factors – see paragraph 21 of Annex F

Step 1 - Tests

13. Collate data on: the costs of decommissioning the project; each company's share of the project decommissioning costs and their total UKCS liability; the company's corporate group UKCS liability, taking account of the interests held by all the group's subsidiary companies; and the net worth (shareholder funds/equity minus intangibles) of both the company and their corporate group. Run the following four tests for all current notice holders and any incoming company.

Test 1: Note project decommissioning costs

Test 2: Compare company share of project decommissioning costs against its net worth

Test 3: Compare company share of UKCS decommissioning costs against its net worth

Test 4: Compare corporate group's share of UKCS decommissioning costs against the group net worth

14. Good quality estimates of decommissioning costs are important when running the above tests. DECC will consider any estimates available from the company concerned and compare these with estimates it holds which were provided by independent third party consultants. We are likely to estimate the costs for large concrete structures on a "left in place" basis as OSPAR derogations have already been given for such structures. The costs for large steel installations which are candidates for OSPAR derogation will be estimated in the light of the timescale, the possibilities of technical advances and the more limited experience of derogation. We are willing to discuss our cost estimates for individual facilities with the owners and if we consider it appropriate amend the costs used in the risk assessment. We do not release detailed figures publicly. Guidance on estimating decommissioning costs has been developed through the Pilot Brownfields Initiative. This is available from the Oil & Gas UK website (www.oilandgasuk.co.uk). Net worth data is taken from the company's published balance sheet.

Step 2 – Company Risk Classification

15. Using the following table, allocate a risk classification to each company for tests 2 and 3 and a classification for each corporate group for test 4.

Class 1	**Class 2**	**Class 3**	**Class 4**
0-30%	31-50%	51-70%	71%+
Company can easily afford costs	Funds are adequate to meet costs	Company should be able to meet costs but may have some difficulty	Company would have considerable difficulty meeting costs

16. The primary financial measure used for assessing a company's capacity to meet its share of the decommissioning costs associated with a licence interest is a comparison of the liability against net worth. The question is, if the decommissioning liability should crystallise today could the company, or any corporate group to which it belongs, meet its share of those costs? If the expected decommissioning costs associated with the licence a company is seeking to acquire ranges between 1% - 50% of the net worth of the company or of the corporate group to which it belongs, we would consider that there are adequate resources to meet those costs when they crystallise. If the potential liability ranges between 51% - 70% of net worth we would consider that the company/group should be able to meet the costs but may have some difficulty in doing so. If the liability exceeds 70% of shareholders funds we would consider that the company/group would have considerable difficulty in meeting the decommissioning. If the initial assessment outlined above indicates the company may have difficulty meeting its obligations, we review the company's/group's accounts, taking note of significant cash balances, liquidity, gearing, capacity to borrow, existing but under-utilised lines of credit, shareholder's guarantees, undertakings etc. We may look at prospects for future revenues from the relevant fields and will always discuss the assessment with the company if it wishes to do so. We will not disclose our assessment outside DECC or the company concerned without its permission.

Step 3 – Section 29 Group Risk Classification

17. Once a classification has been assigned to each current section 29 notice holder and any incoming party it is possible to assess the risk of the group of notice-holders as a whole, i.e. the section 29 group risk. This should be calculated both with and without the presence of any outgoing party to consider the impact of withdrawing their notice.

18. Whether a section 29 group is low, medium or high risk will depend on the balance of class 1, 2 and 3 companies. The classification assumes companies are registered in the UK. If a company is not UK registered it may be discounted when determining the group classification. For example:

- Low risk section 29 groups: If there is a company with a relatively high percentage interest in the field, say above 35%, that is class 1 for test 2 and 3, as they can easily afford both their share of the decommissioning costs of the project and their wider UKCS costs, we are likely to conclude that the section 29 group is low risk. Alternatively if all companies involved are class 2 for tests 2 and 3, as their funds are still considered adequate the section 29 group could be given a low risk allocation.

- Medium risk section 29 groups: Similar to low risk, if there is a company with a relatively high percentage interest that is class 2 for test 2 and 3 or if all companies are class 3 for tests 2 and 3 we are likely to conclude that the section 29 group is medium risk. Class 2 companies have adequate resources to meet the costs. Although class 3 companies should also have adequate funds they may have some difficultly. It is therefore only possible to allocate the section 29 group a medium risk based on class 3 companies as on balance, if all companies are at least of this rating, overall there should be sufficient assets within the section 29 group.

- High risk section 29 groups: If a low or medium risk classification is not justified, by default the section 29 group will be high risk.

19. In addition to the above examples the strength of the corporate groups of the companies will be considered, test 4. The involvement of one or more corporate group with significant resources may be sufficient to allocate a lower risk classification to the section 29 group.

Step 4: Consider Whether to Withdraw Notice

20. Once a section 29 group risk classification has been calculated, the following guidelines are used to indicate whether to withdraw a section 29 notice from an exiting party. These guidelines are indicative and the Secretary of State reserves the discretionary nature of his withdrawal powers. Where DECC judges that the remaining group of section 29 notice holders would be weakened to an unacceptable extent by the departure of a company from it, the Secretary of State will not exercise his discretion to withdraw the notice given under section 29 of the Act from the selling party.

<table>
<tr><th>Section 29 Group Risk</th><th>Withdraw?</th><th>Notes</th></tr>
<tr><td>High</td><td>Do not withdraw</td><td></td></tr>
<tr><td>Medium</td><td>Withdrawal probable if costs are ≤ £25m</td><td rowspan="2">If all current Section 29 holders are class 1 for test 2, the cost threshold may be overruled.

The threshold is only indicative. Experience suggests that estimates above this level can be unreliable. There may be considerable uncertainties due to the type of structure and associated decommissioning complexities.</td></tr>
<tr><td>Low</td><td>Withdrawal probable if costs are ≤ £100m</td></tr>
</table>

21. Qualifying factors:

- If there is an exited company (sold interest and section 29 not withdrawn) in the section 29 group further withdrawals are not considered unless a subsequent transfer is intra-group or the exited company is a result of the following class 2 for test 2 consideration.

- Do not withdraw unless the purchasing company is at least class 2 for test 2. Basically, the incoming company should have adequate funds to meet their share of the decommissioning costs prior to withdrawing the notice on the selling company. This addresses concerns raised by industry during consultation and in representations on specific cases that the Secretary of State should not depend solely on the joint and several nature of the liability but take account of an individual company's ability to fund their share of costs.

- Do not withdraw if only one party left in the section 29 group unless they are class 1 for test 2 and test 3. This takes account of the inherent risk of one party holding 100% of the interests in a project.

- Relevant security agreements will be taken into account. Where a security agreement of the type described in Annex G has been established we are likely to look favourably on the release of a departing licensee. However, this will only be possible if at least 2 other section 29 holders remain. If the transfer will result in 100% ownership the last party to sell will normally be required to 'police' the agreement and their section 29 notice will not be withdrawn.

- We will also take account of any knowledge that the remaining companies wish to sell their interest in the field or may be sold by their corporate parents.

Step 5: Mitigation Measures

22. If the assessment indicates a medium or high risk, we will consider whether the company has a parent or other associate which is UK registered and has sufficient assets to cover decommissioning costs at the appropriate time. We may apply section 30(1)(e) of the Act in respect of installations or section 30(2)(c) in respect of a pipeline and serve a notice under section 29 on the relevant parent or associated party.

23. If the risks to the taxpayer are assessed as unacceptable, section 38(4) of the Act, as amended by the Energy Act 2008, enables the Secretary of State to require a company to provide security if they have been served with a notice under section 29, or have a duty to carry out an approved decommissioning programme. We do not expect to initiate section 38(4) if other mitigation measures, such as serving on associated parties, can be used to reduce the risk. Prior to issuing a notice requiring the provision of security the Secretary of State would first give the company an opportunity to make representations regarding whether they should receive such a notice and consult the Treasury. If such a notice is issued the Secretary of State would respect any company concerns regarding confidentiality. The provisions would only be discussed with the companies directly involved.

24. When considering the risks, the Secretary of State will take account of any relevant security agreements. We are not likely to issue a notice under section 38(4) requiring security if there is a satisfactory security agreement in place.

25. A company which fails to comply with a notice under section 38(4) will be guilty of an offence unless they can prove that they exercised due diligence to avoid the failure. In deciding the best way forward in such a situation the Secretary of State will consider the reasons for the default and continue to look for mechanisms to protect the taxpayer. Where security has been provided in accordance with a notice and the security provider is down rated during the period covered by the security, the Secretary of State will discuss any necessary action with the company. The required action will depend on the new rating and continued standing of the security provider.

26. Details of the relevant 2008 Act provisions and further information regarding security provisions are given in *section 3 and Annex G,* respectively, of this guidance.

New Field Developments

27. New fields may be developed by companies with limited financial resources and DECC may be concerned about their ability to fund decommissioning, especially if something should go wrong in the early phase of the development. When a developer puts forward proposals for a new field we will assess the financial strength of the companies involved, using the stepped process outlined above and taking account of any additional information relevant to the case. Each assessment is confidential but DECC will always be willing to discuss it with the company and would take into account any proposals to establish securities.

28. At this stage we are primarily considering the risk of premature decommissioning resulting from disappointments in the performance of the reservoir or installation. As with existing fields, if we feel that the field is high risk a notice under section 29 may be served on associated parties and, if the risk remains high, we will consider whether to require the provision of security.

29. Where security has been provided, we will reassess the position after say, 6 months of production to decide whether to suspend the security requirement as satisfactory field performance and assurance of future revenues has been demonstrated. In such cases, we would expect to re-instate the security closer to the end of field life as the field reservoir depletes. The net value of the remaining recoverable reserves and the financial position will be reviewed and discussed with the company.

Examples of Risk Assessment Process

Example 1

Decommissioning Costs £10m

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
X	60	£6m	£100m	6%(class 1)	£30m	30%(class1)	£800m	£80m	10%(class 1)
Y	20	£2m	£50m	4%(class 1)	£30m	60%(class3)	£90m	£50m	56%(class 3)
Z	20	£2m	£20m	10%(class 1)	£15m	75%(class4)	£25m	£20m	80%(class 4)

Assessment:

- Company X has a significant percentage interest in the field and can easily afford both its share of the decommissioning costs (tests 2) and its UKCS liability (test 3). Company X is also part of a group with significant resources (class 1 for test 4).
- Companies Y and Z can easily afford their share of the decommissioning costs (test 2) but may have difficulty meeting both their UKCS liability (test 3) and their groups UKCS liability (test 4).
- Decommissioning costs for this project are relatively low.
- Based on the strength of company X, this is a low risk case and risk mitigate is not necessary.

Action 1: Company Y sells to Company A

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
X	60	£6m	£100m	6%(class 1)	£30m	30%(class1)	£800m	£80m	10%(class 1)
A	20	£2m	£15m	13%(class 1)	£10m	67%(class3)	£40m	£15m	37%(class 2)
Z	20	£2m	£20m	10%(class 1)	£15m	75%(class4)	£25m	£20m	80%(class 4)
Y	Withdraw	N/A	£50m	N/A	£28m	56%(class3)	£90m	£48m	53%(class 3)

Assessment:

- The group remains low risk due to inclusion of company X.
- Withdrawal is therefore probable as costs are less than £100m.
- As incoming company (A) can afford its share of the project decommissioning costs (test 2) – withdraw notice from company Y.

Action 2: Company Z sells to Company B

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
X	60	£6m	£100m	6%(class 1)	£30m	30%(class1)	£800m	£80m	10%(class 1)
A	20	£2m	£15m	13%(class 1)	£10m	67%(class3)	£40m	£15m	37%(class 2)
B	20	£2m	£3m	67%(class 3)	£2.5m	83%(class4)	£10m	£4m	40%(class 2)
Z	Exited	N/A	£20m	N/A	£13m	65%(class3)	£25m	£18m	72%(class 4)

Assessment:

- The group remains low risk due to the inclusion of company X.
- As before withdrawal is probable as costs are less than £100m.
- However, withdrawal is not considered unless the incoming company has adequate funds to meet its share of the decommissioning costs. As company B may have difficulty meeting its costs (test 2) – do not withdraw notice from company Z.

Action 3: Company A sells to Company C

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
X	60	£6m	£100m	6%(class 1)	£30m	30%(class1)	£800m	£80m	10%(class 1)
C	20	£2m	£20m	10%(class 1)	£5m	25%(class1)	£50m	£10m	20%(class 1)
B	20	£2m	£3m	67%(class 3)	£2.5m	83%(class4)	£10m	£4m	40%(class 2)
Z	Exited	N/A	£20m	N/A	£13m	65%(class3)	£25m	£18m	72%(class 4)
A	Withdraw	N/A	£15m	N/A	£8m	53%(class3)	£40m	£13m	32%(class 2)

Assessment:

- The group remains low risk due to the inclusion of company X.
- If there is an exited company further withdrawals are only considered if a subsequent transfer is intra-group or, as is the case here, the exited company (Z) was retained because they sold to a company (B) that may have difficulty meeting its share of the project decommissioning costs.
- As the incoming company (C) in this case can afford its share of the project decommissioning costs (test 2) – withdraw notice from company A.

Action 4: Company X sells to Company D

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
D	60	£6m	£50m	12%(class 1)	£38m	76%(class4)	£60m	£45m	75%(class 4)
C	20	£2m	£20m	10%(class 1)	£5m	25%(class1)	£50m	£10m	20%(class 1)
B	20	£2m	£3m	67%(class 3)	£2.5m	83%(class4)	£10m	£4m	40%(class 2)
Z	Exited	N/A	£20m	N/A	£13m	65%(class3)	£25m	£18m	72%(class 4)
X	Exited	N/A	£100m	N/A	£24m	24%(class1)	£800m	£74m	9%(class 1)

Assessment:

- If the notice is withdrawn from company X the section 29 group is no longer low risk.
- Company C is the only company that can easily afford both its share of the project decommissioning costs (test 2) and its UKCS liability (test 3). However, they only hold 20% interest in the field. In order to take comfort from the finances of one company they need to hold a substantial interest, at least over 35%. Given that the other companies may have difficulty meeting their UKCS liabilities, by default the section 29 group would be high risk, if notice withdrawn from company X, unless corporate groups registered in the UK bring sufficient strength to mitigate the risk (test 4).
- Given the relatively modest strength of the corporate groups in this case – do not withdraw notice from company X.

Example 2

Decommissioning Costs £50m

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
X	60	£30m	£250m	12%(class 1)	£60m	24%(class1)	£800m	£100m	12%(class 1)
Y	20	£10m	£150m	7%(class 1)	£30m	20%(class1)	£250m	£50m	20%(class 1)
Z	20	£10m	£80m	12%(class 1)	£15m	19%(class1)	£100m	£20m	20%(class 1)

Assessment:

- All companies can easily afford both their share of the decommissioning costs (test 2) and their UKCS liability (test 3). In addition they are all part of corporate groups that can easily afford their overall UKCS liability.
- This is a low risk case and risk mitigation is not necessary.

Action: Companies X and Y sell to Z

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
Z	100	£50m	£80m	62%(class 3)	£55m	69%(class3)	£100m	£60m	60%(class 3)
X	Exited	N/A	£250m	N/A	£30m	12%(class1)	£800m	£70m	9%(class 1)
Y	Exited	N/A	£150m	N/A	£20m	13%(class1)	£250m	£40m	16%(class 1)

Assessment:

- Due to the inherent risk of one party holding 100% of the interest, withdrawal of notices from exited companies is only considered if the remaining company can easily afford both its share of the decommissioning costs and its UKCS liability (class 1 for tests 2 and 3).
- As company Z is class 3 for tests 2, 3 and 4 - do not withdraw notices from companies X and Y.

Example 3

Decommissioning Costs £250m

Company	% interest	Share of Decom Costs	Net Worth	Test 2	Company UKCS liability	Test 3	Group Net Worth	Group UKCS liability	Test 4
X	60	£150m	£200m	75%(class 4)	£190m	95%(class4)	£250m	£190m	76%(class 4)
Y	40	£100m	£150m	67%(class 3)	£120m	80%(class4)	£170m	£130m	76%(class 4)

Assessment:

- Both companies are likely to have difficulty meeting their share of the decommissioning costs (test 2) and their UKCS liability (test 3).
- This is a high risk case and risk mitigation measures will be considered.
- The corporate groups of both companies are likely to have considerable difficulty meeting their liabilities (test 4) and the risk is therefore not adequately mitigated by serving on the associates.
- Given the high risk and high costs of this project security will be necessary. Prior to serving a notice requiring establishment of security the Treasury will be consulted and the company given an opportunity to make representations.

DECOMMISSIONING SECURITY AGREEMENTS TO WHICH THE SECRETARY OF STATE IS A PARTY

General Background

1. The Secretary of State is not usually a party to the industry's security agreements but the presence of an acceptable agreement may facilitate the withdrawal of a section 29 notice on a departed licensee. DECC has participated in the industry initiative to develop a standard template Decommissioning Security Agreement, (DSA). As far as possible DECC will accept the terms in the standard DSA but it contains options that licence groups will sometimes prefer to use between themselves when the Secretary of State is not a party. The template DSA and associated guidance are available from the Oil & Gas UK website .www.oilandgasuk.co.uk. Although DECC will also consider security agreements that do not utilise the DSA template they would need to meet the same minimum requirements. For simplicity the DSA is referred in this Annex.

2. The over-riding aim of a DSA is to ensure that guaranteed funds (which may include future revenues in appropriate cases) will be available to cover the decommissioning costs at all times. For example, if a company becomes insolvent before decommissioning, the security posted under the DSA would be triggered and held in trust. This security will be equal to the insolvent participant's share of the decommissioning costs reduced by an allowance for their share of any remaining oil and gas reserves and the operating expenditure that would be spent in recovering those reserves, in line with a formula contained in the DSA. This formula underpins the DSA and has to be recalculated regularly by an independent third party to ensure that the levels of security are realistic and up to date.

3. The Secretary of State for Energy and Climate Change may become a party to a DSA to facilitate withdrawal of a section 29 notice from a departing licensee, to ensure that changes to the agreement cannot be made without his written consent, and, in certain cases, to enable him to take action to resolve a default situation.

4. As DSAs are to be stand-alone documents, entirely separate from the JOA (or similar agreement), agreement to any licence assignment granted by DECC's Licensing Section does not imply consent to any change to the parties to the DSA. Such changes should be agreed separately, through the Offshore Decommissioning Unit, by written amendment to the DSA.

5. Cases where 100% ownership results following a licence transfer require a special approach. In cases where there are two or more remaining licensees each party effectively ensures that the other(s) adheres to the agreement (if they do not do this they may become liable for another participant's share, under the joint and several provisions of the Act). However, in cases, where following licence transfer one party will own 100% of the interests, DECC will require a departed licensee to 'police' the DSA. This party will usually be the last licensee to sell their interests, and to ensure they 'police' the agreement effectively their section 29 notice will not be withdrawn. In addition, if this scenario is not already incorporated, the format of the DSA will require amendment to reflect the differences arising from the situation.

6. Where the Secretary of State has concerns about the ability of a group of section 29 notice holders to fund the decommissioning of a project he can initiate section 38(4) of the Petroleum Act 1998 to require security (*see Annex F*). This would only be done if other mitigation measures had not adequately reduced the risk. When section 38(4) is used a DSA is not required. Although the Secretary of State may become a party to a DSA and take the presence of an acceptable agreement into account when considering whether to withdraw a section 29 notice and/or issue a notice under section 38(4), these are commercial agreements setting the security requirements between the companies. Where a section 38(4) notice is issued it will specify what security is required including the amount, the credit rating of security provider and the timing. The Secretary of State will be the beneficiary and establishment of a trust fund is not necessary. There will however be similarities with the Secretary of State's minimum requirements for a DSA and the types of security and risk factor discussed below will apply. DECC will discuss the situation with the company (which has a legal right to object) before issuing a notice under section 38(4).

Minimum Requirements for a DSA to which the Secretary of State is a party

7. DECC recognise the impacts that the security requirements of DSAs can have, particularly on smaller companies. Our requirements are as detailed below but we do encourage proposals for alternative forms of security. Alternatives must provide a similar level of security to letters of credit, i. e. be irrevocable, on demand and issued by a UK body of substance (see below).

8. We require the parties to a DSA to provide security such as cash, irrevocable standby Letters of Credit (LoCs) issued by a Prime Bank, or on-demand (performance) bonds from Prime Banks or issued by an Insurer regulated under the Financial Services and Markets Act 2000. For these purposes the security must be issued by a body established in an EU or OECD country with a UK lending or insurance office and which have an AA rating or better as defined by Standard and Poors, Aa2 rating or better as defined by Moodys or an equivalent rating by another recognised rating agency. We may consider proposals which do not fully meet these criteria and take account of factors such as the level of risk and decommissioning costs and the presence of other parties to the DSA.

9. The DSA should be on a full field basis and should establish a mechanism to allocate a share of the costs to each party. The security should cover each party's share of the pre-tax costs of decommissioning the installations and pipelines in the relevant field. In the event of default, although obligations remain joint and several, in the first instance other parties should cover the share of the default proportionate to their percentage interest.

10. The security should provide at least 100% of estimated costs including site clear-up after the main removal work. In most cases it will also be necessary to add a risk factor to cover the uncertainties surrounding cost calculations. The need for and the amount of this will vary depending on the complexities of the facilities to be decommissioned but in most circumstances will add 50% to the total cost estimate. Unless one party owns 100% of the interests, where the field concerned is in production and future revenues can be reasonably predicted, allowance would be made for those revenues on a post tax

basis. However, salvage value of the equipment can only be discounted if the security covers an FPSO type facility which has real intrinsic value. Following completion of the main removal activities ongoing security to cover the site clear up activities will be required (this amount will be in the range of 1-3% of the total decommissioning costs). Further information on the formula to be used to calculate the costs of decommissioning is contained within the template DSA and its accompanying guidance notes.

11. Unless alternative forms of security are agreed, the DSA should provide for the security in the form of LoCs, on-demand performance bonds or similar, to be renewed annually, 2 months before the next period of security is due to commence. In the event of the failure by any party to renew security before the next period, that party would be in default and the LoC or performance bond would be triggered and the money drawn down and deposited in a regulated Trust Fund to accrue interest until it is needed to pay for decommissioning costs.

12. In addition to cash, LoC or on demand bonds we would accept that a company of substantial financial standing can demonstrate its ability to meet all its potential liabilities without providing a financial security. The particular circumstances of the case and the level of decommissioning costs will determine whether this is feasible and what defines an acceptable financial status. However, the company would as a minimum have sufficient assets to easily afford both its potential liabilities for the project and its wider UKCS portfolio; with costs for each equating to less than 30% of the company's net worth (see Annex F). The assets backing the net worth figure would need to be held by the section 29 notice holder.

13. This approach does not change our policy on parent company guarantees discussed below because it is based on the statutory obligation of the section 29 notice and the assets of the company.

14. The DSA should be drafted to ensure that any potential liability of the Trust Fund to inheritance tax is accounted for in the calculation of the amount of security.

Unacceptable Security

Parent Company Guarantees (PCGs)

15. PCGs are not considered to represent acceptable security for the following reasons (although we are willing to consider any solutions which address them).

16. A standby letter of credit imposes a primary contractual obligation on the issuer to pay a specified sum of money on the happening of a specified event. It can be argued that a PCG is related to the underlying contract and is not therefore a primary obligation on the part of the guarantor. There remains, therefore, the possibility that the guarantor might dispute the basis on which the obligation in the underlying contract has arisen which could result in the matter becoming the subject of litigation.

17. There are companies with interests in the UKCS which are subsidiaries of major overseas companies but do not have significant UK assets and are reliant upon support from the overseas parent. DECC is concerned about the difficulties and potential delays in enforcing a PCG through foreign courts. Delay

could hamper our objective of ensuring timely decommissioning. This situation in turn creates a difficulty in accepting PCGs from UK parents. We are concerned that different approaches could be alleged to discriminate against recipients of section 29 notices whose parents are domiciled in other EU Member States as the Treaty of Rome prohibits discrimination on the basis of nationality. It is not our practice to accept PCGs from European parents. Whilst the Brussels Convention of 1968 ensures that it is possible for judgments obtained in one signatory state to be enforced in another such state, the Convention does not extend to revenue, customs or administrative matters and the recovery of decommissioning costs would be classed as an administrative matter

18. In some cases the parent company may not itself have the long-term financial strength we are looking for and in cases where a subsidiary is in financial difficulty this may indicate that the parent and/or group as a whole is in financial difficulty, as the need for the security to be called upon is most likely to arise in cases where the group as a whole is in financial difficulties. Moreover, in such cases, if the guarantor cannot or will not pay up under the guarantee, the remaining participants would be left without any easily accessible assets to cover the defaulting licensee's share of decommissioning costs. This might therefore expose the Secretary of State to the risks involved in trying to recover decommissioning costs from overseas parent companies.

Independent Audit

19. Estimates of decommissioning costs and of the net value of remaining recoverable reserves used to calculate the required levels of security must be carried out at least every 3 years and may be required annually depending on the project timescales. An independent third party expert approved by DECC must verify this audit process. Further details about the timing and frequency of such audits are contained within the template DSA.

Role of the Secretary of State

20. Where the parties agree to enter into a DSA of the kind described in the preceding paragraphs, the Secretary of State will become a party to the agreement to prevent any alterations being made to it without his consent. Any proposed changes to the agreement, in the event of a licence assignment, for example, would require a separate approval from the Secretary of State.

21. It is also conceivable that in the event of a default by all the other parties to a DSA, the Secretary of State may need to arrange decommissioning and draw on the securities arranged by the parties.

Independence of the DSA

22. The DSA must be a stand-alone document, entirely independent of the JOA and any other similar agreements.

STATUTORY CONSULTEES FOR A DECOMMISSIONING PROGRAMME

The National Federation of Fishermen's Organisations
NFFO Offices
30 Monkgate
York
YO31 7PF
(Tel: 01904 635430)

Scottish Fishermen's Federation
24 Rubislaw Terrace
Aberdeen
AB10 1XE
(Tel: 01224 646944)

Northern Ireland Fishermen's Federation
1 Coastguard Cottages
The Harbour
Portavogie
Co. Down
BT22 1EA
(Tel: 028 42771954)

Global Marine Systems Limited
New Saxon House
1 Winsford Way
Boreham Interchange
Chelmsford
Essex
CM2 5PD
(Tel: 01245 702000)

ANNEX 16
(Ref. 9.19)

OSPAR CONVENTION FOR THE PROTECTION OF THE MARINE ENVIRONMENT OF THE NORTH-EAST ATLANTIC

MEETING OF THE OSPAR COMMISSION (OSPAR)

STOCKHOLM: 26-30 JUNE 2006

OSPAR Recommendation 2006/5 on a Management Regime for Offshore Cuttings Piles

RECALLING Article 2(3)of the Convention for the Protection of the Marine Environment of the North-East Atlantic ("OSPAR Convention"), which, *inter alia*, requires Contracting Parties to take full account of the latest technological developments and practices when adopting programmes and measures and to this end requires Contracting Parties to define with respect to programmes and measures the application of best available techniques (BAT) and best environmental practice (BEP), including, where appropriate, clean technology;

RECALLING Article 5 of the OSPAR Convention, which requires the Contracting Parties to take all possible steps to prevent and eliminate pollution from offshore sources in accordance with the provisions of the Convention, in particular as provided for in Annex III;

RECALLING the programmes and measures contained in OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations;

RECALLING the programmes and measures contained in OSPAR Decision 2000/3 on the Use of Organic-Phase Drilling Fluids (OPF) and the Discharge of OPF-Contaminated Cuttings;

The Contracting Parties to the Convention for the Protection of the Marine Environment of the North-East Atlantic RECOMMEND:

1. Definitions

1.1 For the purpose of this Recommendation:

'BAT'	means best available techniques as defined in Appendix 1 of the OSPAR Convention;
'BEP'	means best environmental practice as defined in Appendix 1 of the OSPAR Convention;
'cuttings'	means solid material removed from drilled rock together with any solids and liquids derived from any adherent drilling fluids;
'cuttings pile'	means an accumulation of cuttings on the sea bed which has been derived from more than one well;
'operator'	means a company controlling the operations of an offshore installation in a part of the maritime area which is under the jurisdiction of a Contracting Party;

'organic-phase drilling fluid (OPF)'	means an organic-phase drilling fluid, which is an emulsion of water and other additives in which the continuous phase is a water-immiscible organic fluid of animal, vegetable or mineral origin;
'other discharges'	means discharges other than discharges of OPF's which contain either chemicals on the OSPAR list of chemicals for priority action or radioactive substances;

2. Purpose and Scope

2.1 The purpose of this Recommendation is to reduce to a level that is not significant, the impacts of pollution by oil and/or other substances from cuttings piles.

2.2 This recommendation is in addition to the programmes and measures contained in OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations and OSPAR Decision 2000/3 on the use of Organic Phase Drilling Fluids (OPF) and the discharge of OPF-Contaminated Cuttings.

2.3 This Recommendation applies to Contracting Parties which have cuttings piles within their jurisdiction in their internal waters or territorial sea, or on their continental shelf.

3. Programmes and Measures

3.1 The Cuttings Pile Management Regime is divided into two stages. Stage 1 involves initial screening of all cuttings piles. This should be completed within 2 years of the Recommendation taking effect. Stage 2 involves a BAT and/or BEP assessment and should, where applicable, be carried out in the timeframe determined in Stage 1.

Stage 1 (to be completed within 2 years of the Recommendation coming into effect)

3.2 Contracting Parties should require that all cuttings piles are screened, using existing information and relevant research, to identify those that require further investigation.

3.3 Where water-based drilling fluids were used and no other discharges have contaminated the cuttings pile, no further investigation is necessary.

3.4 Where organic-phase drilling fluids (OPF) were used and discharged or other discharges have contaminated the cuttings pile the following process should be completed:

3.4.1 Contracting Parties should require that the rate of oil loss and the persistence over the area of seabed contaminated are assessed using existing evidence where this is sufficient to carry out this process, and undertaking the relevant research where more information is needed;

3.4.2 The rate of oil loss should be assessed on the basis of the quantity of oil lost from the cuttings pile to the water column over time. The unit used should be tonnes per year (tonnes/yr);

3.4.3 The persistence should be assessed on the basis of the area of the seabed where the concentration of oil remains above 50mg/kg and the duration that this contamination level remains. The unit used should be square kilometre years (km^2yrs).

3.5 The results of this process should be compared against the following thresholds:

Rate of oil loss to water column:	10 tonnes/yr
Persistence over the area of seabed contaminated:[1]	500 km^2yr

3.6 Where both the rate and persistence are BELOW the thresholds and no other discharges have contaminated the cuttings pile, no further action is necessary and the cuttings pile may be left in situ to degrade naturally.

3.7 Where either the rate of oil loss or the persistence are ABOVE the thresholds, stage 2 should be initiated at a time to be determined by the Contracting Party, taking into account the rate of oil loss, the persistence over the area of seabed contaminated and the timing of the decommissioning of the associated installation.

Stage 2 (to be carried out in the timeframe determined in Stage 1)

3.8 The Contracting Party should require that a study is carried out to determine the best available techniques (BAT) and/or the best environmental practice (BEP) for the cuttings pile.

3.9 The study should characterise the cuttings pile, review the impacts and carry out a comparative assessment to determine BAT and/or BEP.

3.10 Characterisation should include determining the position, area and topography, hydrography, volume, physical characteristics, and chemical content, as well as a biological characterisation.

3.11 The current edition of the publication from Oljeindustriens Landsforening (OLF) 'Guidelines for Characterisation of Offshore Drill Cuttings Piles' (available on www.olf.no) may be used in the completion of the study, or other methods accepted by the Contracting Party.

3.12 Contracting Parties may require that a sampling programme should be used to define the limit of areas contaminated or to determine the effects on the macro-fauna, together with a more detailed characterisation of the cuttings pile.

3.13 When assessing BAT and/or BEP, consideration should include, but not be limited to, the following options:

- Onshore treatment and reuse
- Onshore treatment and disposal
- Offshore injection
- Bioremediation in situ
- Covering in situ
- Natural degradation in situ

3.14 The comparative assessment should be made on the same basis as a comparative assessment made under OSPAR Decision 98/3 on The Disposal of Disused Offshore Installations and include consideration of the following matters:

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1 A persistence of 500 km^2yr could mean an area of $1km^2$ is contaminated for 500 years or an area of 500 km^2 is contaminated for 1 year.

3.14.1 The assessment should consider the potential impacts of the proposed disposal of the cuttings pile on the environment and other legitimate uses of the sea. The assessment should also consider the practical availability of re-use, recycling and disposal options;

3.14.2 The information collated in the assessment should be sufficient to enable a reasoned judgement on the practicability of each of the disposal options, and to allow for an authoritative comparative evaluation;

3.14.3 The assessment of the disposal options should take into account, but need not be restricted to:

a. technical and engineering aspects of the option, including re-use and recycling and the impacts associated with cleaning the cuttings pile while it is offshore;

b. the timing of the decommissioning;

c. safety considerations associated with removal and disposal, taking into account methods for assessing health and safety at work;

d. impacts on the marine environment, including those arising from exposure of biota to contaminants associated with the cuttings pile, other biological impacts arising from physical effects, conflicts with the conservation of species, with the protection of their habitats, or with mariculture, and interference with other legitimate uses of the sea;

e. impacts on other environmental compartments, including emissions to the atmosphere, leaching to groundwater, discharges to surface fresh water and effects on the soil;

f. consumption of natural resources and energy;

g. other consequences to the environment which may be expected to result from the options;

h. impacts on amenities, the activities of communities and on future uses of the environment; and

i. economic aspects

3.14.4 For the matters outlined in 3.14.3, Contracting Parties should require each option to be assessed using appropriate methodologies. The preferred option should be selected by focussing on matters where there are significant differences. The means used to select the preferred option should be described and allow the Contracting Party to make consistent decisions;

3.14.5 The assessment should take into account the inherent uncertainties associated with each option, and should be based upon conservative assumptions about potential impacts. Cumulative effects from the disposal of material in the maritime area and existing stresses on the marine environment arising from other human activities should also be taken into account;

3.14.6 The assessment should also consider what management measures (including responsibilities, resources and funding) might be required to prevent or mitigate adverse consequences of each option, and should indicate the scope and scale of any monitoring that may be required;

3.14.7 The assessment should take account of the decommissioning of the associated installation and especially the decommissioning of any seabed structures, the effect this may have on the cuttings pile and any opportunities that may emerge in relation to carrying out simultaneous activities to minimise the overall environmental impacts;

3.14.8 The assessment should also take account of potential disturbance of the pile due to other legitimate uses of the sea after decommissioning of the associated installation;

3.14.9 The assessment, which should be based on scientific principles and should be linked back to the supporting evidence and arguments, should be sufficient to enable the Contracting Party to reach a judgement on the proposal for BAT and/or BEP. Documentation should identify the origins of the data used, together with any relevant information on the quality assurance of that data.

3.15 The Contracting Party, taking account of the conclusions of the comparative assessment, should approve a plan, including a timeframe, to implement BAT and/or BEP.

3.16 The Contracting Party should consider whether to require reporting to confirm that the plan is progressing as expected and/or independent confirmation (e.g. from relevant fishing organisations) that it has been completed satisfactorily.

4. Entry into Force

4.1 This Recommendation has effect from 30 June 2006.

5. Implementation Report

5.1 Reports on the implementation of this Recommendation should be submitted by Contracting Parties with cuttings piles in their jurisdiction, using as far as possible the format set out in Appendix 1.

5.2 The reports should be submitted to the appropriate OSPAR subsidiary body in the meeting cycle 2008/2009. Subsequent reports on implementation should be made if deemed necessary by the Commission.

Appendix 1

Format for Reporting on Implementation of OSPAR Recommendation 2006/5 on a Management Regime for Offshore Cuttings Piles

(Note: In accordance with paragraph 5.1 of the Recommendation, this format should be used as far as possible in implementation reports)

I. Implementation Report on Compliance

Country:	
Reservation applies	yes/no
Is measure applicable in your country?	yes/no*

If not applicable, then state why not (e.g. no relevant cuttings piles)

....

....

....

....

Means of Implementation:

by legislation	by administrative action	by negotiated agreement
yes/no*	yes/no*	yes/no*

Please provide information on:

specific measures taken to give effect to this measure;

b. any special difficulties encountered, such as practical or legal problems, in the implementation of this measure;

c. the reasons for not having fully implemented this measure should be spelt out clearly and plans for full implementation should be reported;

d. if appropriate, progress towards being able to lift the reservation.

....

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* Delete whichever is not appropriate.

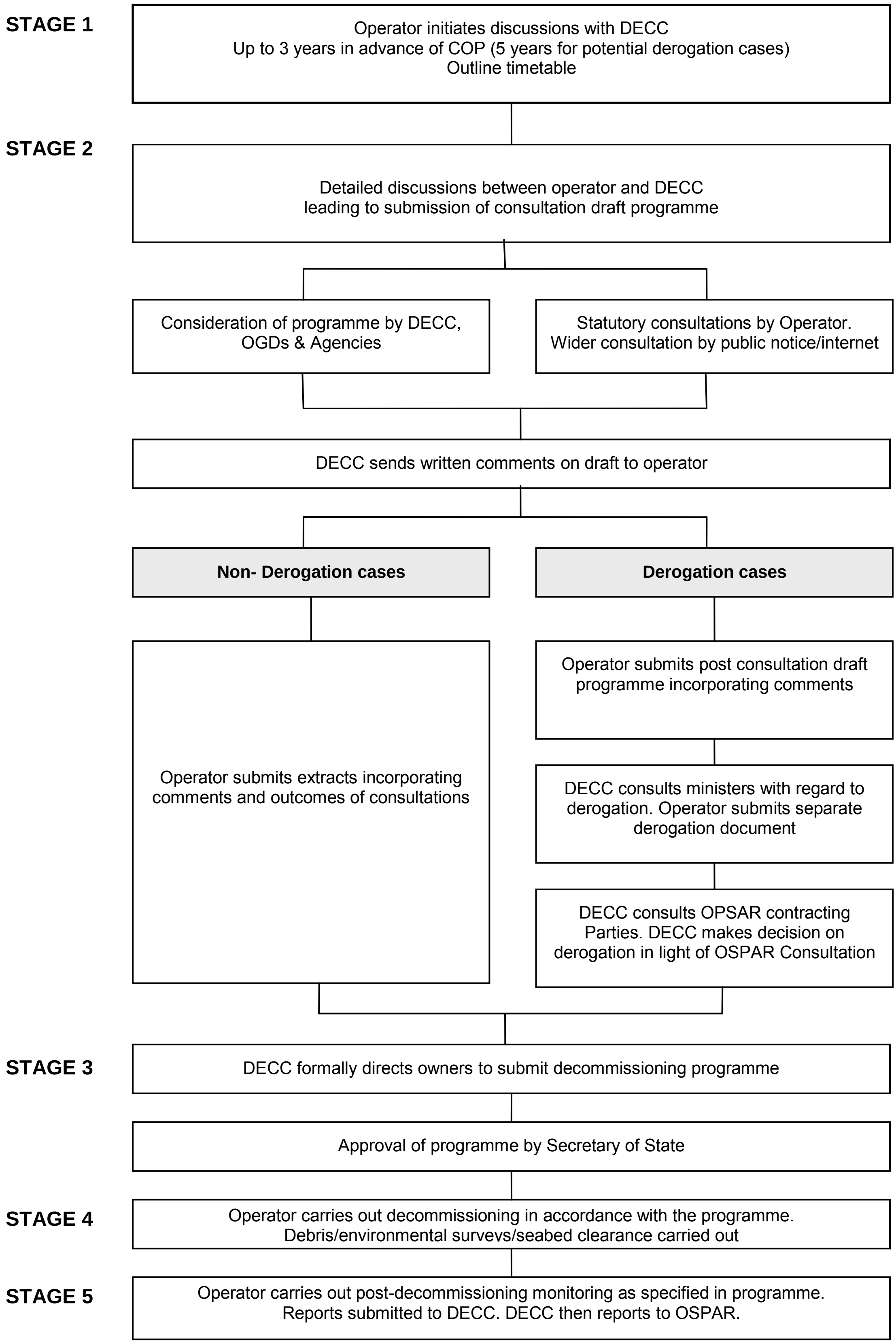
II. Implementation Report on Effectiveness

NOTE: The following data and information should be reported to the extent possible. Please state the reasons, if some required data and information cannot be provided.

Total number of cuttings piles for which Stage 1 Assessment has been completed	
Total number of cuttings piles for which Stage 2 Assessment has been completed	
Total number of cuttings piles receiving:	
onshore treatment and reuse	
onshore treatment and disposal	
offshore injection	
bioremediation *in situ*	
covering *in situ*	
natural degradation *in situ*	
other treatment option explain…	

For cuttings piles assessed under Stage 1		
Field	Rate of oil loss (te/yr)	Persistence (km^2yr)

DECOMMISSIONING PROGRAMME PROCESS: FLOWCHART



INDEX

References are to paragraph numbers, e.g. 3.23; Annex E.17. Annex B has four annexes marked, e.g. Annex B/3.

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APPENDIX C

Generic Decommissioning Relief Deed

DECOMMISSIONING RELIEF DEED

Between

THE LORDS COMMISSIONERS OF HER MAJESTY'S TREASURY

And

[COMPANY]

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THIS DECOMMISSIONING RELIEF DEED is made on the day of 20

BETWEEN:

(1) **THE LORDS COMMISSIONERS OF HER MAJESTY'S TREASURY** (the "**Government Counterparty**"); and

(2) [**COMPANY**], a company registered in [England and Wales] with company number [NUMBER], and whose registered office is at [ADDRESS] (the "**Company**").

RECITALS:

(A) The Company (which term shall for the purposes of these Recitals refer also to any Associated Entity) is currently liable to carry out, or may in the future be made subject to a duty to carry out, decommissioning of wells, installations or pipelines in the United Kingdom or the UKCS with which it has been associated in the past, with which it is currently associated or with which it may be associated in the future.

(B) In order to meet the cost of such liabilities, the Company has entered into or may in the future enter into security arrangements with third parties. As tax relief on expenditure in relation to decommissioning is granted only when the decommissioning is carried out, such security is given or received without allowance being made for such tax relief.

(C) To give the Company and/or its financiers certainty as to the basis on which tax relief will be available and therefore enable security to be given or received net of tax relief and facilitate possible additional investment by the Company, the Government Counterparty and the Company have agreed to enter into this Deed. In reliance on the undertakings given by the Government Counterparty in this Deed, the Company may be able to provide security to, or agree to receive security from, third parties net of tax relief, and/or may make additional investments in oil and gas assets in the United Kingdom or on the UKCS.

(D) The Government Counterparty considers that providing certainty as to the basis on which tax relief will be available is likely to encourage the development of the oil and gas resources of the United Kingdom and the UKCS and the undertakings given by the Government Counterparty in this Deed are therefore in the interests of the United Kingdom.

AGREEMENT:

1. Definitions and Interpretation

1.1 Words and phrases used in this Deed (including the Recitals) have the following meanings, unless the context requires otherwise:—

"Accounting Period"	shall mean an accounting period of the Claimant for the purposes of corporation tax (including Ring Fence Corporation Tax) and Supplementary Charge as determined in accordance with Enactment Date Legislation, including the notional accounting period provided for in section 165 of CAA 2001 if appropriate, or if the Claimant is not within the charge to corporation tax, shall mean the period of twelve months ending on an accounting reference date of the Claimant (or equivalent date under the law of its jurisdiction of incorporation);

“Affected Parties”	has the meaning given to it in Clause 7.2.1;
“Alternative Schedule”	means a schedule issued by the Government Counterparty in accordance with Clause 2.3 or Clause 2.4 as an alternative to Schedule 1;
“Apportionment Notice”	has the meaning given to it in Paragraph 8.4 of Schedule 1;
“Associated Entity”	any entity which is a “qualifying company” within the meaning of section 80(3) of FA 2013 and which, on the assumption that the Company is within one or more of paragraphs (a) to (d) of section 30(1) of the Petroleum Act 1998, would be associated with the Company for the purposes of paragraph (e) of that section;
“Available Profits”	means the assessable profits chargeable to PRT in any Chargeable Period in respect of any Field that are capable of being reduced by relief for Decommissioning Expenditure (whether or not such profits could in the absence of such relief be relieved from Tax by virtue of any oil allowance or other relief or allowance), save that any calculation of those profits shall ignore any prior reduction that resulted from the incurring of Decommissioning Expenditure, whether by virtue of section 83 of Finance Act 2013 or through the regular operation of other statutory provisions relating to PRT;
“Business Day”	means a day (other than a Saturday or Sunday) which is not a public holiday or bank holiday in London;
“CAA 2001”	means the Capital Allowances Act 2001;
“Change in Tax Law”	means any change in the statutory regime for the computation of profits for the purposes of the Tax in question (including the amount of any loss, relief or allowance) from the regime in place on the Enactment Date, or any change after the Enactment Date in any published guidance or practice of HMRC which relates to that regime;
“Chargeable Period”	shall mean a chargeable period of six months for the purposes of PRT ending at the end of June or December in any year;
“Claim”	means a claim for a Difference Payment made by the Company or an Associated Entity under this Deed (but also includes the submission of a Claim Statement pursuant to Clause 6.1.1 or Clause 6.1.3 which could give rise to a payment under Clause 6.1.5(b));
“Claimant”	means the person making a Claim (being the Company or an Associated Entity);
“Claimant Certificate”	has the meaning given to it in Clause 6.1.4(b);
“Claim Statement”	a written statement disclosing a Claim and made in such form as the Government Counterparty shall specify by public notice;
“Connected Person”	means a person connected with the Claimant for the purposes of section 575 of CAA 2001 (as that section has effect on the Enactment Date);

"CT"	means corporation tax charged under CTA 2009;
"CTA 2009"	means the Corporation Tax Act 2009;
"CTA 2010"	means the Corporation Tax Act 2010;
"CT Relief"	means any reduction in CT liability or CT repayment, not being RFCT Relief (nor SC Relief);
"Current Legislation"	means the legal regime for the computation of profits for the purposes of the Tax in question (including the amount of any loss, relief or allowance and the rate at which such Tax is charged) at the time a Claim is made, as the same may be interpreted by the courts of any part of the United Kingdom from time to time, and all related published guidance or practice of HMRC;
"Decommissioning Expenditure"	means:— (a) in relation to Ring Fence Corporation Tax and Supplementary Charge, "general decommissioning expenditure" as defined in section 163 of CAA 2001 and expenditure which is qualifying expenditure by virtue of section 416ZA of that Act; and (b) in relation to PRT, the expenditure specified in paragraphs (i) and (j) of section 3(1) of the Oil Taxation Act 1975, which, in either case, is "decommissioning expenditure" within the meaning of section 81 of FA 2013 and is also:— (i) incurred in relation to the ring fence trade which is or has at any time been carried on by the Company or an Associated Entity (or a company that was an Associated Entity at the time such trade was carried on), as the case may be, in the UKCS or the territorial waters of the United Kingdom; or (ii) where the Claimant is a qualifying company within the meaning of section 80(3)(d) of FA 2013, incurred by it as a result of an Imposition relating to a cross-boundary field (as referred to in that section) where the person in default is party to a joint operating agreement, unit operating agreement or similar agreement (and has carried on a ring fence trade) in relation to that field, construing the statutory references in this definition as references to the relevant provisions as they have effect on the Enactment Date;
"Decommissioning Relief"	means any reduction in Tax liability, or any Tax repayment, which results from incurring Decommissioning Expenditure, including where such reduction arises as a result of a surrender of losses by the party incurring the expenditure;
"Deductible Expenditure"	means any expenditure, other than Decommissioning Expenditure, that is deductible or otherwise allowable for the purposes of a particular Tax and that arises otherwise than as a result of or in connection with an Imposition;

"Deed"	means this Decommissioning Relief Deed, including all of its Schedules;
"Defaulter Certificate"	has the meaning given to it in Clause 6.1.4(b);
"Defaulting Party"	means the party whose failure, or the forfeiture of whose Licence Interest Share, has given rise to an Imposition;
"Difference Payment"	has the meaning given to it in Clause 5.2 (but also includes a payment made pursuant to Clause 6.1.5(b));
"Due Date"	means in relation to any particular payment the date on which that payment is due, being:— (a) in the case of a Claim under Clause 6.1.1 or Clause 6.1.3, the date specified in Clause 6.1.5(a) (as may be modified by Clause 6.5.3 and/or Clause 6.5.7, as appropriate); (b) in the case of a Claim under Clause 6.2.1 or Clause 6.2.3, the date specified in Clause 6.2.5(a) (as may be modified by Clause 6.5.3 and/or Clause 6.5.7, as appropriate); and (c) in the case of a Recovered Relief Repayment (as defined in Clause 6.4.1), the date specified in Clause 6.4.2 or Clause 6.4.3 as applicable;
"Effective Date"	means the date first above written;
"Enactment Date"	means 17 July 2013, being the day on which FA 2013 entered into force;
"Enactment Date Legislation"	means the statutory regime for the provision of reliefs and allowances in respect of Decommissioning Expenditure and the use of losses arising as a result of incurring Decommissioning Expenditure which is in place on the Enactment Date (but subject to any Permitted Amendments), as the same may be interpreted by the courts of any part of the United Kingdom from time to time, together with all published guidance or practice of HMRC as at that date which relates to that regime;
"Field"	means an oil field determined in accordance with Schedule 1 of the Oil Taxation Act 1975;
"FA 2013"	means the Finance Act 2013;
"HMRC"	means Her Majesty's Revenue and Customs;
"HMRC Certificate"	means a certificate issued by HMRC in accordance with the process set out in Schedule 3;
"Imposition"	means any circumstance where:— (a) the Claimant is required to incur Decommissioning Expenditure due to:— (1) the owners of the Relevant Property having failed to carry out its decommissioning; or

	(2) the failure of another party to meet its obligations to incur Decommissioning Expenditure under (i) a joint operating agreement, unit operating agreement or similar agreement, or any agreement entered into between some or all of the parties to any such agreement that is ancillary thereto, (ii) an agreement under which a person has disposed (whether by way of sale, lease, farm-in, exchange or otherwise) of an interest in the Relevant Property or a decommissioning security agreement between some or all of the current owners of the Relevant Property and the previous owners of the Relevant Property, or (iii) a construction and tie-in, transportation, processing or similar agreement (whether or not the Claimant is a party to any such agreement), or any agreement entered into between some or all of the parties to any such agreement that is ancillary thereto, (and in determining whether such circumstance has arisen, the fact that the Claimant may have had joint and several liability for the obligations of such other party by virtue of statute shall be ignored); or (b) the Claimant is required to incur Decommissioning Expenditure in respect of a Licence Interest Share which it acquired as the result of forfeiture, forced sale or similar transfer made in consequence of a default under a joint operating agreement, unit operating agreement or similar agreement, but shall exclude (other than for the purposes of the definition of Defaulting Party):— (i) any such circumstance where the Defaulting Party is an affiliate of the Claimant at the time of the failure or forfeiture; and (ii) any such circumstance to the extent that it arises as a result of the Claimant (or an affiliate of the Claimant) being party to or entering into any arrangement or understanding with the Defaulting Party (or with an affiliate of the Defaulting Party) the main purpose or one of the main purposes of which is that any person should receive or become entitled to any right or benefit or increased right or benefit under this Deed in respect of Decommissioning Expenditure incurred as the result of an Imposition (or what would, apart from this paragraph (ii) or paragraph (i), constitute an Imposition);
“Imposition Decommissioning Expenditure”	means Decommissioning Expenditure incurred as a result of an Imposition (subject where relevant to the provisions of Paragraphs 2.3 and 5.4 of Schedule 1);
“Licence Interest Share”	means the percentage beneficial interest of any licensee in a petroleum production licence as specified under the relevant joint operating agreement, unit operating agreement or similar agreement or, where there is a single licensee, means the entire beneficial interest in the licence;
“Ordinary Decommissioning Expenditure”	means Decommissioning Expenditure other than Imposition Decommissioning Expenditure;

"Paragraph 15"	means paragraph 15 of Schedule 17 to the Finance Act 1980 (as it applies at the Enactment Date);
"Party"	means a party to this Deed and its respective legal and/or statutory successors and permitted assignees and "Parties" means both of them;
"Permitted Amendment"	means any change in law from Enactment Date Legislation comprising legislation that:— (a) is introduced with the purpose and effect of preventing the circumvention of, or the exploitation of shortcomings in, the statutory regime for the provision of relief for Decommissioning Expenditure; and (b) is consistent with the principles set out in Paragraphs 2 to 6 of Schedule 4 and is enacted in furtherance of them or any of them;
"PRT"	means petroleum revenue tax charged under the Oil Taxation Act 1975 and any other similar field-based or project-based tax which is introduced in addition to or as a replacement for petroleum revenue tax;
"PRT Reference Amount"	means an amount calculated in accordance with Paragraph 5 of Schedule 1;
"PRT Relief"	means Decommissioning Relief in respect of PRT;
"Reference Amount"	means an RFCT Reference Amount, an SC Reference Amount or a PRT Reference Amount, as the case may be;
"Relevant Property"	means any property associated with an undivided legal interest under a petroleum production licence or with rights arising under a joint operating agreement, unitisation agreement or similar agreement relating to a Field or pipeline;
"RFCT" or "Ring Fence Corporation Tax"	means corporation tax charged under CTA 2009 and CTA 2010 in respect of ring fence trades and any other tax on profits which is introduced in addition to or as a replacement for such corporation tax (but excluding Supplementary Charge);
"RFCT Reference Amount"	means an amount calculated in accordance with Paragraph 3 of Schedule 1 or, in the case of Imposition Decommissioning Expenditure, in accordance with Paragraph 6 of Schedule 1;
"RFCT Relief"	means Decommissioning Relief in respect of RFCT;
"SC" or "Supplementary Charge"	means the charge in respect of ring fence trades imposed by Chapter 6 of Part 8 of CTA 2010;
"SC Reference Amount"	means an amount calculated in accordance with Paragraph 4 of Schedule 1 or, in the case of Imposition Decommissioning Expenditure, in accordance with Paragraph 7 of Schedule 1;
"SC Relief"	means Decommissioning Relief in respect of Supplementary Charge;

"Similar Deed"	means any deed made on substantially the same terms as this Deed (including any deed which differs from this Deed only in the fact that it contains an Alternative Schedule);
"Tax"	means any tax, levy, impost, duty, charge, assessment or fee of any nature that is imposed by any taxing authority in the United Kingdom;
"Tax Capacity"	means profits in any Tax Period against which the Decommissioning Expenditure in question may be utilised so as to reduce or eliminate such profits for the purposes of the Tax in question (whether or not such profits would otherwise be relieved from Tax by virtue of any oil allowance or other relief or allowance);
"Tax Period"	means an Accounting Period or a Chargeable Period, as appropriate;
"Tax Return"	means (i) in respect of Ring Fence Corporation Tax and Supplementary Charge, a corporation tax self-assessment or other return as required by Tax legislation, and (ii) in respect of PRT, a return pursuant to section 1(1)(b) of the Petroleum Revenue Tax Act 1980;
"UKCS"	means the "UK sector of the continental shelf" as that term is defined in section 1313(3) of CTA 2009.

1.2 Unless the context requires otherwise or the contrary is stated:—

1.2.1 the singular includes the plural and vice versa;

1.2.2 (other than in the definition of Enactment Date Legislation) a reference to any enactment, order, regulation, directive, code, licence or similar instrument includes all enactments or instruments made under it and any amendment, re-enactment or replacement of it;

1.2.3 clause headings, clause descriptions and examples are for convenience only and do not affect the interpretation of this Deed;

1.2.4 a reference to a **"Clause",** "**Schedule**", "**Paragraph**" or part thereof is a reference to a clause or schedule in this Deed or to a paragraph of such a schedule;

1.2.5 a person shall be taken to be an "**affiliate**" of another person for the purposes of this Deed if it controls, is controlled by or is under common control with that other person, and for this purpose "control" has the meaning given to it in section 1124 of CTA 2010 (as that section has effect on the Enactment Date) and "controlled" shall be interpreted accordingly;

1.2.6 **"includes"** and its variations are to be construed without limitation;

1.2.7 **"persons"** includes individuals, firms, corporations, unincorporated associations and statutory authorities, and all references to persons shall include their successors and permitted assignees; and

1.2.8 in Schedule 3, **"participator"** has the meaning given to it in section 12 of the Oil Taxation Act 1975.

2. Commencement and Term

2.1 This Deed shall take effect and commence on the Effective Date.

2.2 The Parties hereby agree that this Deed is irrevocable and shall endure without limit of time, unless and until mutually terminated by both Parties by written agreement.

2.3 At any time in order to improve the operation of this Deed or to give greater certainty as to the amount of Tax relief which will be available in respect of Decommissioning Expenditure, the Government Counterparty may issue to the Company a schedule which, as an alternative to Schedule 1 of this Deed, provides a different basis for the calculation of any of the Reference Amounts (an **"Alternative Schedule"**). If the Government Counterparty issues an Alternative Schedule, it shall take effect only if the Company so elects in accordance with its terms but shall in that event determine the relevant Reference Amount for the purposes of any Claim made thereafter unless a further Alternative Schedule is issued by the Government Counterparty and accepted by the Company.

2.4 If the Government Counterparty issues an Alternative Schedule to the signatory to a Similar Deed it shall also as soon as is reasonably practicable issue that Alternative Schedule to the Company.

3. Scope of Deed

3.1 Subject to Clauses 3.2 and 3.6, this Deed shall apply in relation to Decommissioning Expenditure incurred by the Company or any Associated Entity.

3.2 Where for the purposes of Paragraph 15 a loss is treated as an allowable loss falling to be relieved against assessable profits of the Company or an Associated Entity as an old participator (a "**Predecessor**"), then subject to Paragraph 9.1 of Schedule 1 to this Deed, insofar as this Deed applies in relation to PRT:—

3.2.1 references to Decommissioning Expenditure being incurred by the Company or an Associated Entity shall be construed as including so much of the Decommissioning Expenditure incurred by the new participator in relation to which the Predecessor is the old participator as gives rise to that loss;

3.2.2 references to Decommissioning Relief arising to or being obtained by the Company or an Associated Entity shall be construed as including Decommissioning Relief resulting from that loss; and

3.2.3 the other provisions of this Deed shall apply so as to give full effect to the foregoing,

provided that the Predecessor shall have no greater right or entitlement under this Deed than it would have had if it had incurred the relevant part of the Decommissioning Expenditure itself.

3.3 Clause 3.4 applies where:—

3.3.1 any Claimant makes a Claim on the basis envisaged in Clause 3.2; and

3.3.2 if such Decommissioning Expenditure as gives rise to the Claim had fallen to be relieved against assessable profits of the Claimant as an old participator for the purposes of Paragraph 15, the Claimant would have been obliged pursuant to a contract with a third party to pay any Decommissioning Relief received to such third party.

3.4 Where this Clause 3.4 applies, the Claimant shall be obliged within thirty (30) days of receipt to pay to the third party in question an amount equal to any Difference Payment received in respect of the Decommissioning Expenditure referred to in Clause 3.3.2.

3.5 Clause 3.6 applies where:—

3.5.1 Decommissioning Expenditure is incurred by any person entitled to make a claim under this Deed or a Similar Deed and the Decommissioning Expenditure would be Imposition Decommissioning Expenditure but for the operation of the exclusion at paragraph (i) of the definition of Imposition; and

3.5.2 some or all of such Decommissioning Expenditure would, if it had been incurred by the Defaulting Party (and, accordingly, section 84(2) of FA 2013 had not been applicable), have been treated for the purposes of Paragraph 15 as giving rise to an allowable loss that fell to be relieved against assessable profits of the Company or an Associated Entity as an old participator.

3.6 Where this Clause 3.6 applies then, insofar as this Deed applies in relation to PRT (and subject to Paragraph 9.1 of Schedule 1):—

3.6.1 references to Decommissioning Expenditure being incurred by the Company or an Associated Entity shall be construed as including so much of the Decommissioning Expenditure incurred by the person referred to in Clause 3.5.1 as would have given rise to the loss referred to in Clause 3.5.2;

3.6.2 references to Decommissioning Relief arising to or being obtained by the Company or an Associated Entity shall be construed as including Decommissioning Relief resulting from that loss; and

3.6.3 the other provisions of this Deed shall apply so as to give full effect to the foregoing,

provided that the Company or (as the case may be) the Associated Entity shall have no greater right or entitlement under this Deed than it would have had if it had incurred the relevant part of the Decommissioning Expenditure itself.

3.7 Where any Claimant makes a Claim in the circumstances set out in Clause 3.5 and, if such Decommissioning Expenditure as is the subject of the Claim had been incurred by the Defaulting Party and had fallen to be relieved against assessable profits of the Claimant as an old participator for the purposes of Paragraph 15 (on the assumption that section 84(2) of FA 2013 was not applicable), the Claimant would have been obliged pursuant to a contract with the Defaulting Party to pay any Decommissioning Relief received to the Defaulting Party, the Claimant shall be obliged within thirty (30) days of receipt to pay to the person who incurred such Decommissioning Expenditure an amount equal to any Difference Payment received in respect of it.

3.8 If any company which is an Associated Entity (and is not already party to a Similar Deed) ceases to be an Associated Entity of the Company, or expects that it will cease to be an Associated Entity within the next ninety (90) days, then by a date no later than ninety (90) days after ceasing to be an Associated Entity such company may by written notice require the Government Counterparty to enter into a Similar Deed.

3.9 On receipt of notification under Clause 3.8 the Government Counterparty shall use reasonable endeavours to comply within ninety (90) days, provided that the company in question can show that it is:—

3.9.1 a "qualifying company" within the meaning of section 80(3) of FA 2013; and

3.9.2 liable to be served with a notice under either of section 29 or 34 of the Petroleum Act 1998.

3.10 The Government Counterparty shall not enter into an agreement with any other person for purposes similar to those set out in the recitals to this Deed on terms more favourable to such person than are afforded to the Company under this Deed (or agree to an amendment to the terms of any such agreement which has the effect of making them more favourable) unless it shall also promptly thereafter offer to the Company the opportunity to amend this Deed so as to incorporate those more favourable terms.

4. Warranties

4.1 Each Party warrants to the other Party, as at the Effective Date and as at the date on which any Difference Payment becomes due:—

(a) that it has the power and capacity (i) to execute this Deed and any other documentation relating to this Deed to which it is a party, (ii) to deliver this Deed and any other documentation relating to this Deed that it is required by this Deed to deliver, and (iii) to perform its obligations under this Deed, and that it has taken or will take all necessary action to authorise that execution, delivery and performance, including, in the case of the Government Counterparty, by procuring the necessary appropriation of funds;

(b) that the execution, delivery and performance referred to in Clause 4(a) do not violate or conflict with any law applicable to it, any order or judgment of any court or other agency of government applicable to it or any contractual restriction binding on it; and

(c) that its obligations under this Deed constitute its legal, valid and binding obligations, enforceable in accordance with their respective terms (regardless of whether enforcement is sought in a proceeding in equity or at law).

4.2 The Company warrants and represents that it is a "qualifying company" within the meaning of section 80(3) of FA 2013 as at the Effective Date.

5. Difference Payments

5.1 In respect of each Tax Period that ends after the Effective Date, the Government Counterparty shall, subject to and in accordance with this Clause 5 and Clause 6, pay:—

5.1.1 to the Company any Difference Payment due in respect of Decommissioning Expenditure incurred by the Company in that Tax Period (and, in relation to PRT, any earlier Tax Period); and

5.1.2 to any Associated Entity any Difference Payment due in respect of Decommissioning Expenditure incurred by such Associated Entity in that Tax Period (and, in relation to PRT, any earlier Tax Period).

5.2 Subject to the remaining provisions of this Clause 5, a payment (a "**Difference Payment**") shall be due to a Claimant in respect of a Tax Period if and to the extent that:—

5.2.1 the aggregate amount of RFCT Relief or CT Relief obtained by the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) in any period by virtue of Decommissioning Expenditure incurred by the Claimant in that Tax Period, together with any Difference Payments already due to or obtained by the Claimant under this Clause 5.2.1 by virtue of that expenditure, shall be less than the RFCT Reference Amount for that Tax Period; or

5.2.2 the aggregate amount of SC Relief obtained by the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) in any period by virtue of Decommissioning Expenditure incurred by the Claimant in that Tax Period, together with any Difference Payments already due to or obtained by the Claimant under this Clause 5.2.2 by virtue of that expenditure, shall be less than the SC Reference Amount for that Tax Period; or

5.2.3 in relation to a Field, the aggregate amount of PRT Relief obtained by the Claimant in that Tax Period and any earlier Tax Period by virtue of Decommissioning Expenditure which it has incurred in that Tax Period and any Decommissioning Expenditure which it has incurred in an earlier Tax Period, together with any Difference Payments in respect of PRT (before any reduction pursuant to Clause 5.3) already due to or obtained by the Claimant by virtue of that expenditure, shall be less than the PRT Reference Amount for that Tax Period.

5.3 Adjustments shall be made to a Difference Payment due under Clause 5.2.3, or to the RFCT Reference Amount, on the following basis:—

5.3.1 any such Difference Payment shall:—

(a) to the extent that it arises as a result of Imposition Decommissioning Expenditure, be reduced by 50%; and

(b) to the extent that it arises as a result of Ordinary Decommissioning Expenditure, be reduced to reflect the additional Ring Fence Corporation Tax and Supplementary Charge (the "**Additional Tax**") that would have been chargeable in any Tax Period, under the applicable legislation that was in force at the Enactment Date, had the Difference Payment (before any reduction under this Clause 5.3.1) been an actual repayment of PRT (but for the avoidance of doubt, if paragraph 3.3 of Schedule 1 applies then the Additional Tax so chargeable shall be the Ring Fence Corporation Tax and Supplementary Charge that would have been chargeable had the Defaulting Party received a repayment of PRT of that amount);

5.3.2 in a case where PRT Relief is obtained by the Claimant in respect of Imposition Decommissioning Expenditure incurred in a Tax Period and the PRT Relief gives rise to an increase in the Claimant's liability to Ring Fence Corporation Tax and Supplementary Charge of more than 50% of the amount of the PRT Relief, the excess shall be added to the RFCT Reference Amount for that period; and

5.3.3 in a case where PRT Relief is obtained by the Claimant in respect of Ordinary Decommissioning Expenditure incurred in a Tax Period and the PRT Relief gives rise to an increase in the Claimant's liability to Ring Fence Corporation Tax and Supplementary Charge of more than the prevailing rate of Ring Fence Corporation Tax and Supplementary Charge (taking into account the effect of section 330B of

CTA 2010) multiplied by the PRT Relief, the excess shall be added to the RFCT Reference Amount for that period.

5.4 Without prejudice to Clause 5.5, no Difference Payment shall arise in respect of Ordinary Decommissioning Expenditure except to the extent that:—

5.4.1 there is a Change in Tax Law (not being a Permitted Amendment) which results in the amount of Decommissioning Relief being less than it would have been under Enactment Date Legislation and which does not (unless Paragraph 4.3 of Schedule 1 applies) consist of a change in the rate at which the Tax in question is charged; or

5.4.2 the Claim is made in circumstances where the Reference Amount is calculated in accordance with Paragraph 3.3 or Paragraph 4.4 of Schedule 1.

5.5 Except in the case of a Claim in respect of Imposition Decommissioning Expenditure under Clause 5.2.1 or Clause 5.2.2, no Difference Payment shall be due to the extent that it arises because a Change in Tax Law has reduced the profits taken into account for the purposes of any Tax.

5.6 Where a Claim is made in circumstances where the Reference Amount is calculated in accordance with Paragraph 3.3 or Paragraph 4.4 of Schedule 1:—

5.6.1 the amount of any Difference Payment shall be no greater than the Decommissioning Relief or Difference Payment that could have been claimed by the affiliate that is the Defaulting Party; and

5.6.2 the aggregate amount of all such Difference Payments shall not exceed the aggregate of the Decommissioning Relief or Difference Payments that could have been claimed by that affiliate,

on the assumption that the affiliate in question had itself incurred the Decommissioning Expenditure that is the subject of the relevant Claim or Claims.

5.7 For the avoidance of doubt, Clauses 5.4 and 5.5 shall not prevent any Difference Payment being increased pursuant to Clause 6.1.5(b) or Clause 6.2.5(b).

6. Claims

6.1 <u>Claim Statements for Imposition Decommissioning Expenditure</u>

6.1.1 Within four (4) years of the end of any Accounting Period in which the Company or an Associated Entity becomes entitled to a Difference Payment in respect of RFCT or SC as a result of incurring Imposition Decommissioning Expenditure, or incurs Imposition Decommissioning Expenditure and thereby becomes entitled to Decommissioning Relief in respect of RFCT or SC, it may submit to the Government Counterparty a Claim Statement setting out the Decommissioning Relief (if any) that it expects to receive under Current Legislation in respect of that expenditure, the relevant Reference Amount(s) and calculations showing the Difference Payment(s) (if any) it considers to be due under Clause 5 for such Accounting Period by virtue of that expenditure.

6.1.2 Each Claim Statement submitted pursuant to Clause 6.1.1 shall include or be accompanied by:—

(a) a copy of the Claimant's draft accounts or management accounts for the Accounting Period or, where the Claimant makes a declaration in accordance with Clause 6.3.5, a set of pro forma accounts relating to its ring fence operations in the United Kingdom and the UKCS;

(b) evidence that the Imposition has occurred;

(c) evidence that the Decommissioning Expenditure has been incurred and as to when payment has been or will be made in respect of it, and confirmation that the work to which such Decommissioning Expenditure relates has been carried out;

(d) a certificate from an officer of the Claimant certifying that the contents of the Claim Statement are correct and complete to the best of the knowledge and belief of the Claimant having made due enquiry, and certifying whether (and, if so, the extent to which) any of the Decommissioning Expenditure has involved, directly or indirectly, a payment to a Connected Person; and

(e) such other documentation or evidence of a similar nature as the Government Counterparty may reasonably require and shall have specified by public notice to holders of Similar Deeds.

6.1.3 At any time after the end of any Chargeable Period in which the Company or an Associated Entity becomes entitled to a Difference Payment in respect of PRT as a result of incurring Imposition Decommissioning Expenditure, or incurs Imposition Decommissioning Expenditure and thereby becomes entitled to Decommissioning Relief in respect of PRT, it may submit to the Government Counterparty a Claim Statement setting out the Decommissioning Relief (if any) that it expects to receive under Current Legislation in respect of that expenditure, the relevant Reference Amount(s) and calculations showing the Difference Payment(s) (if any) it considers to be due under Clause 5 for such Chargeable Period.

6.1.4 Each Claim Statement submitted pursuant to Clause 6.1.3 shall include or be accompanied by:—

(a) a copy of its Tax Return for PRT for the Chargeable Period or, where the Claimant makes a declaration in accordance with Clause 6.3.5, a set of pro forma accounts relating to its ring fence operations in the United Kingdom and the UKCS;

(b) the relevant HMRC Certificate or HMRC Certificates in respect of which the Claim is made, each being a certificate showing Available Profits in relation to the relevant Field of either (i) the Claimant and its predecessors in title, whether or not still in existence (a "**Claimant Certificate**"), or (ii) the Defaulting Party and its predecessors in title, whether or not still in existence (a "**Defaulter Certificate**"), at the Claimant's option, provided that (subject to Clause 6.7.2), where in respect of the first Claim in relation to any particular Imposition the Claimant has submitted one or more Claimant Certificates (or, as the case may be, Defaulter Certificates), any further HMRC Certificate submitted in relation to such Imposition shall also be a Claimant Certificate (or, as the case may be, a Defaulter Certificate);

(c) evidence that the Imposition has occurred;

(d) evidence that the Decommissioning Expenditure has been incurred and as to when payment has been or will be made in respect of it, and confirmation that the work to which such Decommissioning Expenditure relates has been carried out;

(e) a certificate from an officer of the Claimant certifying that the contents of the Claim Statement are correct and complete to the best of the knowledge and belief of the Claimant having made due enquiry and certifying whether (and, if so, the extent to which) any of the Decommissioning Expenditure has involved, directly or indirectly, a payment to a Connected Person; and

(f) such other documentation or evidence of a similar nature as the Government Counterparty may reasonably require and shall have specified by public notice to holders of Similar Deeds.

6.1.5 Following receipt by the Government Counterparty of a Claim Statement in accordance with Clause 6.1.1 or 6.1.3, but subject to Clauses 6.4 and 6.5:—

(a) the Government Counterparty shall, within sixty (60) days in the case of a Claim under Clause 6.1.1 and one hundred and twenty (120) days in the case of a Claim under Clause 6.1.3 (the last day of the specified period in either case being the Due Date) pay to the Claimant a sum equal to the Difference Payment(s) claimed (if any) in such Claim Statement; and

(b) to the extent that the Claimant has not by the Due Date received a payment of Decommissioning Relief equal to the amount of any Decommissioning Relief shown in such Claim Statement as payable pursuant to Current Legislation, payment of an amount equal to the shortfall shall be due by that date under this Clause 6.1.5 (which payment shall be deemed for the purposes of this Deed to constitute a Difference Payment or, if a Difference Payment is made under paragraph (a) above, an increase in that Difference Payment).

6.2 <u>Claim Statements for Ordinary Decommissioning Expenditure</u>

6.2.1 Within four (4) years of the end of any Accounting Period in which the Company or an Associated Entity becomes entitled, as a result of incurring Ordinary Decommissioning Expenditure (in that period or an earlier period), to a Difference Payment in respect of Ring Fence Corporation Tax or Supplementary Charge, it may submit to the Government Counterparty a Claim Statement setting out the Decommissioning Relief (if any) that it expects to receive under Current Legislation in respect of that expenditure, the relevant Reference Amount(s) and calculations showing the Difference Payment(s) it considers to be due under Clause 5 for such Accounting Period by virtue of that expenditure.

6.2.2 Each Claim Statement submitted pursuant to Clause 6.2.1 shall include or be accompanied by:—

(a) a copy of the Claimant's Tax Return or, where the Claimant is making a Claim on the basis of the Tax Capacity of an Associated Entity, the Tax Return of such Associated Entity for such Accounting Period and evidence of its Tax Capacity;

(b) evidence that the Decommissioning Expenditure has been incurred and as to when payment has been or will be made in respect of it, and confirmation that the work to which such Decommissioning Expenditure relates has been carried out;

(c) a certificate from an officer of the Claimant certifying that the contents of the Claim Statement are correct and complete to the best of the knowledge and belief of the Claimant having made due enquiry and certifying whether (and, if so, the extent to which) any of the Decommissioning Expenditure involved, directly or indirectly, a payment to a Connected Person; and

(d) such other documentation or evidence of a similar nature as the Government Counterparty may reasonably require and shall have specified by public notice to holders of Similar Deeds.

6.2.3 Within four (4) years of the end of any Chargeable Period in which the Company or an Associated Entity becomes entitled, as a result of incurring Ordinary Decommissioning Expenditure (in that period or any earlier period), to a Difference Payment in respect of PRT, it may submit to the Government Counterparty a Claim Statement setting out the Decommissioning Relief (if any) that it expects to receive under Current Legislation in respect of that expenditure, the relevant Reference Amount(s) and calculations showing the Difference Payment(s) it considers to be due under Clause 5 for such Chargeable Period by virtue of that expenditure.

6.2.4 Each Claim Statement submitted pursuant to Clause 6.2.3 shall include or be accompanied by:—

(a) a copy of the Claimant’s Tax Return or, where the Claimant is making a Claim on the basis of the Tax Capacity of an Associated Entity, the Tax Return of such Associated Entity for such Chargeable Period;

(b) the relevant HMRC Certificate in respect of which the Claim is made, being a certificate showing Available Profits of the Claimant or of the Associated Entity, as may be applicable, in relation to the relevant Field;

(c) evidence that the Decommissioning Expenditure has been incurred and as to when payment has been or will be made in respect of it, and confirmation that the work to which such Decommissioning Expenditure relates has been carried out;

(d) a certificate from an officer of the Claimant certifying that the contents of the Claim Statement are correct and complete to the best of the knowledge and belief of the Claimant having made due enquiry and certifying whether (and, if so, the extent to which) any of the Decommissioning Expenditure involved, directly or indirectly, a payment to a Connected Person; and

(e) such other documentation or evidence of a similar nature as the Government Counterparty may reasonably require and shall have specified by public notice to holders of Similar Deeds.

6.2.5 Following receipt by the Government Counterparty of a Claim Statement in accordance with Clause 6.2.1 or 6.2.3 (being a Claim Statement which discloses an entitlement to a Difference Payment), but subject to Clauses 6.4 and 6.5:—

(a) the Government Counterparty shall, within sixty (60) days in the case of a Claim under Clause 6.2.1 and one hundred and twenty (120) days in the case of a Claim under Clause 6.2.3 (the last day of the specified period in either case being the "Due Date") pay to the Claimant a sum equal to the Difference Payment(s) claimed in such Claim Statement; and

(b) to the extent that the Claimant has not by the Due Date received a payment of Decommissioning Relief equal to the amount of Decommissioning Relief shown in such Claim Statement as payable pursuant to Current Legislation, the amount of the Difference Payment due to such Claimant shall be increased by the amount of any shortfall.

6.3 <u>General Provisions regarding Claim Statements</u>

6.3.1 A Claimant shall be entitled to submit more than one Claim Statement in respect of any Tax Period.

6.3.2 Where a Claimant wishes to make Claims in respect of both Imposition Decommissioning Expenditure and Ordinary Decommissioning Expenditure for the same Tax Period, it shall make the Claims in separate Claim Statements (and may submit the Claim Statements separately).

6.3.3 The time limit on making Claims in Clauses 6.2.1 and 6.2.3 shall not prevent a Claim being made within thirty (30) days following the conclusion of an enquiry by HMRC into the subject-matter of the Claim.

6.3.4 Payment pursuant to this Clause 6 shall be made by the applicable Due Date in pounds sterling by direct bank transfer or equivalent transfer of immediately available funds to the Company or the Associated Entity (as the case may be), to the credit of such account as may have been notified to the Government Counterparty in accordance with Clause 12 or by inclusion of the relevant details in the Claim Statement in respect of which payment is to be made.

6.3.5 In cases where the Claimant is not resident for tax purposes in the United Kingdom and is not carrying on a trade in the United Kingdom through a permanent establishment in the United Kingdom, it shall in any Claim Statement include declarations to that effect and to the effect that:—

(a) it has no liability to corporation tax, PRT, Ring Fence Corporation Tax or Supplementary Charge; and

(b) the Imposition Decommissioning Expenditure to which the Claim relates was incurred by it in compliance with its obligations under a notice issued under section 29 or section 34 of the Petroleum Act 1998 or by reason of it being liable to be issued with such a notice.

6.4 <u>Repayment of Difference Payment where Decommissioning Relief subsequently received</u>

6.4.1 If the Government Counterparty makes a Difference Payment pursuant to this Deed and (whether before or after such Difference Payment is received) the Claimant or an affiliate of the Claimant obtains Decommissioning Relief in respect of the Decommissioning Expenditure to which the Difference Payment (or any part thereof) relates, being Decommissioning Relief which was not taken into account in the calculation of such Difference Payment (a "**Recovered Relief**"), then the Claimant shall within thirty (30) days of obtaining the Recovered Relief pay to the Government Counterparty an amount equal to the lesser of such Recovered Relief and such Difference Payment (a "**Recovered Relief Repayment**").

6.4.2 Except to the extent that the Recovered Relief corresponds to Decommissioning Relief in respect of which payment is made under Clause 6.1.5(b) or Clause 6.2.5(b), the Recovered Relief Repayment shall be treated as being paid in order to reverse an overpayment and interest shall be charged thereon in accordance with Clause 6.6.2, taking the Due Date as being the date on which the Difference Payment in question was paid.

6.4.3 To the extent that the Recovered Relief corresponds to Decommissioning Relief in respect of which payment is made under Clause 6.1.5(b) or Clause 6.2.5(b):—

(a) where in addition to the Decommissioning Relief the Claimant receives any related interest or repayment supplement (a "**Time Value Payment**"), the proportion of that Time Value Payment (if any) that is determined in accordance with Clause 6.4.4 shall be deemed to form part of the Recovered Relief; and

(b) the corresponding part of the Recovered Relief Repayment (together with such amount of the Time Value Payment as is deemed to form part of it in accordance with paragraph (a) above) shall be treated as being paid in order to reverse an overpayment and interest shall be charged thereon in accordance with Clause 6.6.2, taking the Due Date as being the date on which the Recovered Relief was obtained.

6.4.4 In order to ascertain the proportion of a Time Value Payment referred to in Clause 6.4.3(a), there shall be determined the period for which the Time Value Payment is intended to compensate the Claimant for not having obtained the Recovered Relief (the "**Time Value Period**"). The proportion relevant for the purposes of Clause 6.4.3(a) shall be equal to such proportion of the Time Value Period as falls on and after the date on which payment is made under Clause 6.1.5(b) or Clause 6.2.5(b). Where it cannot be determined whether the Time Value Payment was intended to compensate the Claimant in respect of a particular period of time, or such period cannot be ascertained to an appropriate degree of accuracy, then the apportionment of the Time Value Period shall be made on a just and reasonable basis.

6.5 <u>Due Date in special cases</u>

Requests for further information or evidence

6.5.1 If in connection with a Claim Statement the Government Counterparty reasonably determines that further information or evidence is required in order to enable it to assess the validity of the Claim, the amount of any Difference Payment or any other matter relevant to the Claim, then the Government Counterparty shall within sixty (60) days of receipt of the Claim issue to the Claimant a notice setting out details of the information or evidence required (an "**Information Request**"). The Due Date for the payment of so much of the Difference Payment as is the subject of the Information Request shall be set in accordance with Clause 6.5.3 (but without prejudice to the Due Date for the remainder (if any) of such Difference Payment).

6.5.2 Within twenty (20) days of receipt of an Information Request, the Claimant shall provide the information or evidence therein specified, make such amendments to its Claim Statement as are appropriate or, in any given case, set out in writing the reasons why any particular information or evidence cannot be provided or is not required (the "**Claimant Response**").

6.5.3 Within thirty (30) days of receipt of a Claimant Response, the Government Counterparty shall (i) if it is then satisfied as to the matters giving rise to the Information Request and no new such matters have been disclosed or discovered, make payment in accordance with Clause 6.1.5 or Clause 6.2.5 (as the case may be) but taking the Due Date as being the date falling thirty (30) days after receipt of the Claimant Response, or (ii) in any other case, make a further Information Request within thirty (30) days of receipt of the Claimant Response, in which event the process described in Clauses 6.5.1 and 6.5.2 and this Clause 6.5.3 shall be repeated.

6.5.4 The Government Counterparty and the Claimant may, instead of or in addition to the steps described at Clauses 6.5.1 to 6.5.3, engage in any informal calls, meetings, correspondence or discussions in order to seek to settle the matters giving rise to the Information Request.

6.5.5 If within sixty (60) days of the first Information Request relating to any particular matters being received by the Claimant those matters have not been resolved as contemplated by Clause 6.5.3(i), then either Party may by written notice to the other declare the matter in dispute and the provisions of Clauses 6.5.10 and 6.5.11 shall apply accordingly.

6.5.6 Where a Difference Payment has been made, the Government Counterparty may from time to time require the Claimant to provide information or evidence regarding the incurring of the relevant Decommissioning Expenditure, the making of payment in respect of it and such other information or evidence as is reasonably required in order to enable the Government Counterparty to establish that the amount of the Difference Payment was and remains correct.

Paragraph 8 Claims

6.5.7 In any case where Paragraphs 8.2 to 8.4 of Schedule 1 are engaged (including in any case where they apply by virtue of Paragraph 3.3.2 or Paragraph 4.4.2 of Schedule 1), the time limits set out in this Clause 6 (and in particular in Clause 6.1.5(a) or Clause 6.2.5(a), as may be applicable) shall not commence until the later of (i) the date on which the Government Counterparty issues the related Apportionment Notices and (ii) the date on which they would otherwise commence. Any related Due Date or other time for payment shall be adjusted as required.

Disputed payments

6.5.8 If the Government Counterparty disputes in good faith any Difference Payment as calculated by a Claimant and set out in a Claim Statement, it shall make payment of the undisputed amount on or before the applicable Due Date and shall give notice to the Claimant of the amount in dispute and the reasons for disputing it on or before the date falling thirty (30) days after that Due Date.

6.5.9 The Government Counterparty and the Claimant shall seek in good faith to settle the disputed amount as soon as reasonably possible.

6.5.10 If the Government Counterparty and the Claimant are unable to settle the dispute and thirty (30) days have passed since the date on which notice of the dispute was given under Clause 6.5.5 or, as the case may be, Clause 6.5.8, then either of them may take such action as is permitted by this Deed, including resorting to the English courts.

6.5.11 Any adjustment payment required to be made in accordance with the resolution of a dispute shall be made within thirty (30) days of that resolution.

6.6 Interest

6.6.1 If the Claimant or the Government Counterparty fails to pay any amount due under this Deed by the applicable Due Date then, subject to Clause 6.6.2, interest shall be payable on that amount at an annual rate equal to the base lending rate set by the Bank of England applicable from time to time plus three per cent (3%) from and including that date to but excluding the date payment is made.

6.6.2 If the Claimant or the Government Counterparty is required to pay an amount following resolution of a request for further information or evidence or of a dispute (as envisaged in Clause 6.5) or in accordance with Clause 6.4 or Clause 6.7, interest shall be payable on that amount:—

(a) where the Claimant is required to pay, at the rate designated as the late payment rate; or

(b) where the Government Counterparty is required to pay, at the rate designated as the repayment interest rate,

in both cases for the purposes of the Taxes and Duties, Etc (Interest Rate) Regulations 2011 (SI 2011/2446) as those may be amended from time to time or any successor legislation, from (i) where Clause 6.4 applies, the Due Date as determined thereunder, (ii) where Clause 6.5.3 or Clause 6.5.7 applies, the Due Date for the original Claim (or Claims), or (iii) where Clause 6.7 applies:—

(aa) the date on which payment was received by the Claimant in the case of an overpayment to the Claimant; or

(bb) the Due Date for the original Claim in the case of an underpayment to the Claimant.

6.7 Amended information

6.7.1 If, following the end of any Tax Period in respect of which a Claim has been made, either the Government Counterparty or the Claimant considers or becomes aware that the information used to calculate the Difference Payment in such Claim was incorrect, or further information becomes available which results in a different calculation of the Difference Payment such that the Difference Payment ought to have been of a different amount, then that party shall, by notice to the other, present an amended Claim Statement setting out the correct Difference Payment. The provisions of this Clause 6 shall apply mutatis mutandis to such amended Claim Statement as if it were a Claim Statement submitted by the Claimant on a timely basis, save that:—

(a) where the original Difference Payment ought to have been greater, the sum due under the amended Claim shall be the amount by which the original Difference Payment was insufficient and shall be treated for the purposes of this Deed as forming part of the same Difference Payment as the original Difference Payment;

(b) where the original Difference Payment ought to have been less, the Claimant shall pay to the Government Counterparty the amount by which the original Difference Payment was excessive; and

(c) any interest shall be calculated in accordance with Clause 6.6.2.

6.7.2 If a Claimant has made a Claim under Clause 6.1.3 and has accordingly submitted a Claimant Certificate or, as the case may be, a Defaulter Certificate (the "**Initial Certificate**") and, when submitting a subsequent Claim in relation to the same Imposition, wishes instead to submit an HMRC Certificate of the other kind (the "**Alternative Certificate**"), then it shall include a statement to that effect as part of the first Claim for which the Alternative Certificate is submitted. In that event, all previous Claims in relation to the Imposition for which the Initial Certificate was submitted shall, with effect from the date of receipt of the first Claim for which the Alternative Certificate is submitted, be treated as if they were Claims made using the Alternative Certificate and Clause 6.7.1 shall apply accordingly. A Claimant shall be entitled to change to an Alternative Certificate only once in respect of any particular Imposition.

6.8 Consent to disclosure

By submitting any Claim Statement, the Claimant authorises HMRC to disclose to the Government Counterparty such information regarding its financial and tax affairs as may be necessary or desirable in order to enable the Government Counterparty to verify the contents of the Claim Statement or to investigate whether an adjustment payment is due pursuant to Clause 6.7.

6.9 Tax gross-up

6.9.1 Any sum payable by the Government Counterparty to the Company or an Associated Entity (as the case may be) under this Deed shall be paid free and clear of any deduction or withholding whatsoever, save only as may be required by law.

6.9.2 If any deduction or withholding is required by law to be made from any payment by the Government Counterparty under this Deed (other than a payment of interest made pursuant to Clause 6.6), the Government Counterparty shall increase the amount of the payment by such additional amount as is necessary to ensure that the net amount received and retained by the Company or the Associated Entity (as the case may be) (after taking account of any deduction or withholding and of any credit for Tax obtained in respect of such deduction or withholding) is equal to the amount which it would have received and retained had the payment in question not been subject to any deduction or withholding.

6.9.3 If the Company or an Associated Entity (as the case may be):—

(a) is subject to Tax in respect of any payment by the Government Counterparty under this Deed (other than a payment of interest made pursuant to Clause 6.6); or

(b) would have been subject to Tax but for the availability of any Tax relief,

then the Government Counterparty shall increase the amount of the payment by such additional amount as is necessary to ensure that the net amount received and retained by the Company or Associated Entity after taking account of all Tax, or the net amount that would have been received and retained but for the availability of the Tax relief, is equal to the amount which it would have received and retained had the payment in question not been subject to Tax or, as the case may be, the Tax relief had not been used. In the case of Clause 6.9.3(b), the additional amount shall become due and payable only if and when the Company or Associated Entity shows that the Tax relief that was set against the payment would have reduced or eliminated an actual liability to Tax and that the Tax that would, accordingly, not otherwise have been due has been paid.

6.10 Recovery of amounts received from third parties

6.10.1 Where a Difference Payment has been made under this Deed and a person (the "**Compensated Party**") receives a Compensating Payment, the Company shall pay or procure the payment of an amount equal to such Compensating Payment (less any Retainable Amount) to the Government Counterparty, provided that no such payment shall be due:—

(a) unless (i) the Compensated Party is, or is an affiliate of, the recipient of the Difference Payment, or (ii) the recipient of the Difference Payment (or any affiliate of the recipient) is party to an arrangement under which it benefits or has benefitted as a result of or in connection with the actual or potential receipt of the Compensating Payment; or

(b) to the extent it exceeds the Difference Payment.

6.10.2 A "**Compensating Payment**" is any payment made by or recoverable from any person (which may include any taxing authority outside the United Kingdom, but not HMRC) by way of compensation, or under any agreement, commitment, indemnity or covenant to pay, or by way of a repayment of Tax, to the extent that it relates to the same subject matter as the Difference Payment referred to in Clause 6.10.1 and arises as a result of or in connection with:—

(a) the Company, an Associated Entity or the Compensated Party having incurred or become liable to incur any Imposition Decommissioning Expenditure (or Decommissioning Expenditure that would be Imposition Decommissioning Expenditure but for the operation of either of the exclusions at paragraphs (i) and (ii) of the definition of Imposition); or

(b) the Company, an Associated Entity or the Compensated Party having benefitted from the carry-back of relief for the purposes of PRT because the Company, an Associated Entity or the Compensated Party incurred Decommissioning Expenditure.

The "**Retainable Amount**" is so much of a Compensating Payment as must be retained by the Compensated Party in order to secure that it is in no better and no worse a position (after Tax) than it would have been had the Decommissioning Expenditure to which the Compensating Payment relates been met by another person at the time it was originally incurred.

6.10.3 The Company shall, and shall (to the extent possible) procure that any person falling within Clause 6.10.1(a) who is potentially entitled to a Compensating Payment shall, seek to recover any Compensating Payment to which it is or becomes entitled.

6.10.4 To the extent that Decommissioning Expenditure of any person falling within Clause 6.10.1(a) corresponds to a Compensating Payment that has not resulted in a payment under Clause 6.10.1 in circumstances where payment is due thereunder, it shall not for the purposes of this Deed be regarded as Decommissioning Expenditure of that person or any Associated Entity thereof. To the extent that it has been so regarded and not dealt with under Clause 6.10.1, such adjustments shall be made to any calculation, amount or payment as are necessary to secure that it is effectively disregarded.

6.11 Claims agent

The Government Counterparty may appoint an agent to deal with the processing of Claim Statements in accordance with this Clause 6 and related matters (a "**Claims Agent**"). The Government Counterparty shall notify the Company of the appointment of any Claims Agent and provide full details of where and to whom Claim Statements should be submitted and any related correspondence directed. Notwithstanding the appointment of a Claims Agent, the Government Counterparty shall remain primarily liable in respect of its obligations under this Deed.

7. Change in Law

7.1 If at any time following the date of this Deed there is a change in law (other than a Change in Tax Law or any other change in law relating to any Tax) which has or will have the unintended effect of materially impeding or frustrating the operation of this Deed, then the Company may issue to the Government Counterparty a notice (an "**Amendment Request**") requesting that the Parties seek to agree such amendments to this Deed as may be required in order to remedy, to the extent possible, the effect of the change in law.

7.2 On receiving an Amendment Request from the Company (or from another person made in relation to the same change of law under a Similar Deed), the Government Counterparty shall use reasonable endeavours to:—

7.2.1 notify all the persons who are party to Similar Deeds (together with the Company, the "**Affected Parties**") and are not aware of the Amendment Request that it has been made; and

7.2.2 discuss with any Affected Party that notifies the Government Counterparty of its desire to be involved in the discussions the issues raised by the Amendment Request (and any equivalent requests made by other Affected Parties) and agree such amendments as may be necessary, provided that (i) such amendments may and must be incorporated into this Deed and all Similar Deeds in the like manner, and (ii) doing so would not prejudice the position of the Government Counterparty in any material respect (ignoring for this purpose its position under this Deed and any Similar Deed) and would not be contrary to law or public policy.

7.3 Where such amendments have been agreed between the Government Counterparty and the Affected Parties, the Government Counterparty and the Company shall ensure that this Deed is altered accordingly.

8. Anti-Abuse

8.1 For the purposes of calculating a Reference Amount under this Deed (and in particular under Paragraph 6 or Paragraph 7 of Schedule 1), the provisions of sections 164, 165A to 165E and 416ZC to 416ZE of CAA 2001 and Part 5 of FA 2013 (GAAR) shall apply in the same way as they apply for the purposes of calculating a liability to Tax.

8.2 In Clause 8.1:—

8.2.1 references to sections are to those sections in the form they have as part of Enactment Date Legislation; and

8.2.2 it shall be assumed for the purposes of applying sections 164, 165A to 165E and 416ZC to 416ZE of CAA 2001 that the person wishing to make a Claim is carrying on a ring fence trade (but only so that the condition in section 165C(1)(a), section 165E(1)(a) or, as the case may be, section 416ZA(1)(a) is satisfied).

8.3 The Government Counterparty and the Company have entered into this Deed in a spirit of good faith. If the Company or any Associated Entity has entered into any Inappropriate Arrangement which would in the absence of the counteracting effect of this Clause 8.3 have secured an Entitlement, then any Difference Payment shall be no greater than it would have been in the absence of the Inappropriate Arrangement (or, where only part of the Inappropriate Arrangement is attributable to an Inappropriate Purpose, no greater than it would have been in the absence of that part).

8.4 For the purposes of this Clause 8 and Schedule 4:—

8.4.1 a person enters into an "**Inappropriate Arrangement**" if it enters into a transaction or arrangement, or includes a feature in a transaction or arrangement, the main purpose or one of the main purposes of which is to enable the Company or an Associated Entity to obtain an Entitlement which would not otherwise be obtained and which is to any extent inconsistent with the principles set out in Paragraphs 2 to 6 of Schedule 4 (an "**Inappropriate Purpose**"); and

8.4.2 "**Entitlement**" means an actual or contingent entitlement to a Difference Payment or an increased Difference Payment under Clause 5 of this Deed.

8.5 A transaction or arrangement shall not be regarded as having an Inappropriate Purpose solely by virtue of the fact that it consists of the undertaking or procurement of decommissioning in the ordinary course (as to which, see Paragraph 1 of Schedule 4), but any such transaction or arrangement will nevertheless constitute an Inappropriate Arrangement if it has, or includes a further feature which has, as one of its main purposes, an Inappropriate Purpose.

9. Confidentiality of Information

9.1 The Government Counterparty shall treat as confidential all information provided by or on behalf of the Company or any Associated Entity under or in connection with this Deed, including Claim Statements, (together the **"Claimant Confidential Information"**) and shall not disclose the Claimant Confidential Information without the prior written consent of the Company or the Associated Entity (as the case may be), save that consent shall not be required for disclosure:—

9.1.1 to HMRC;

9.1.2 to the extent required by any applicable laws or judicial process, provided that the Company or the Associated Entity (as the case may be) has been notified of the intended disclosure at least seven (7) days before it is made;

9.1.3 to Affected Parties of an Amendment Request made pursuant to Clause 7.1; or

9.1.4 to the extent that the Claimant Confidential Information is in or lawfully comes into the public domain other than by breach of this Clause 9.1.

9.2 If the Company or an Associated Entity requests and receives an HMRC Certificate in relation to any of its predecessors in title or in relation to the Licence Interest Share of any other person, it shall treat as confidential the information relating to such parties contained in any such HMRC Certificate (the **"Taxpayer Confidential Information"**) and shall not disclose the Taxpayer Confidential Information without the prior written consent of the party concerned, save that consent shall not be required for disclosure:—

9.2.1 to HMRC or the Government Counterparty;

9.2.2 as may reasonably be required in connection with its consideration of the acquisition (whether by way of sale, lease, farm-out, exchange or otherwise) of an interest in a Field, the negotiation of decommissioning security arrangements, the calculation of security under such arrangements, the consideration of potential liability to decommissioning or the making of Claims;

9.2.3 to the extent required by any applicable laws or judicial process, provided that the party concerned has been notified (where practicable) of the intended disclosure at least seven (7) days before it is made;

9.2.4 to the extent that the Taxpayer Confidential Information is in or lawfully comes into the public domain other than by breach of this Clause 9.2.

10. Third Parties

10.1 Except as set out in Clause 10.2, the Parties intend that no provision of this Deed shall by virtue of the Contracts (Rights of Third Parties) Act 1999 ("**1999 Act**") confer any benefit on, or be enforceable by, any person who is not a Party.

10.2 Subject to the remaining provisions of this Clause 10, by virtue of the 1999 Act:—

10.2.1 this Deed is intended to be enforceable by an Associated Entity (or in the case of Clauses 3.8 and 3.9, an entity which was formerly an Associated Entity);

10.2.2 Clause 3.4 of this Deed is intended to be enforceable (against the Claimant only) by any third party with whom a Claimant has such a contract as is referred to in Clause 3.3.2;

10.2.3 Clause 3.7 of this Deed is intended to be enforceable (against the Claimant only) by any person who has incurred such Decommissioning Expenditure as is referred to in that Clause; and

10.2.4 Clause 9.2 of this Deed is intended to be enforceable (but only against the Company or an Associated Entity) by any person to whom the Taxpayer Confidential Information relates.

10.3 Notwithstanding Clause 10.2, this Deed may be amended or varied by the issue of an Alternative Schedule in accordance with Clause 2.3 or 2.4, or amended, varied or rescinded by the Parties, in either case without notice to or the consent of any Associated Entity or other third party.

10.4 The enforcement of the rights of any Associated Entity or third party under Clause 10.2 shall be conditional on the acceptance by the Associated Entity or third party of the terms of this Deed, and in making any claim under this Deed such Associated Entity or third party shall be taken to have accepted them.

11. Assignment

11.1 Subject to the remaining provisions of this Clause 11, neither Party shall assign or transfer to any person any of its rights or obligations in respect of this Deed.

11.2 The Company or any Associated Entity may assign its rights under this Deed by way of security to or in favour of:—

11.2.1 any bank or other financial institution in relation to the financing of commercial activities which the Company or an Associated Entity carries on primarily on the UKCS or in the territorial waters of the United Kingdom; or

11.2.2 any entity engaged to undertake decommissioning work in the ordinary course for or on behalf of the Company or an Associated Entity in relation to the decommissioning of any installation or pipeline on the UKCS or in the territorial waters of the United Kingdom.

11.3 The Government Counterparty may transfer its rights and obligations under this Deed in whole or in part so long as, following the transfer, it remains the case that a Minister of the Crown is liable to make any payments which may become due under this Deed to a Claimant.

11.4 As a separate and independent stipulation the Government Counterparty undertakes that if any such assignment or transfer as is referred to in Clause 11.3 is made and as a result any right of the Company or any Associated Entity under this Deed is rendered unenforceable, or the performance of any obligation by either Party arising under this Deed is rendered illegal or the rights of the Company or any Associated Entity under this Deed are adversely affected, then the Government Counterparty shall be liable to pay such compensation to the Company or such Associated Entity as is necessary to restore the Company or such Associated Entity to the position it would have been in had such assignment or transfer not taken place.

12. Notices

12.1 Except where expressly provided otherwise in this Deed, any notice or other communication authorised or required by this Deed to be given or sent by either Party to the other (a **"Communication"**) shall be in writing and signed by an authorised representative of the sender.

12.2 All Communications given by one Party to the other Party pursuant to this Deed may be delivered by hand, by facsimile, by commercial courier or, within the United Kingdom, by first class, recorded delivery or special delivery post, or by such other means as the Parties may agree from time to time.

12.3 Communications shall be sent to the address or facsimile number specified for the receiving Party in Schedule 2 and shall be marked to the attention of the person named in Schedule 2. Either Party may, by written notice to the other, change its contact details given in Schedule 2.

12.4 Communications delivered in accordance with this Clause 12 shall be effective as follows:—

12.4.1 if delivered by hand or by commercial courier, on the Business Day of delivery or on the first Business Day after the date of delivery if delivered on a day other than a Business Day (or after 1800 local time on a Business Day);

12.4.2 if sent by first class, recorded delivery or special delivery post within the United Kingdom, on the second Business Day after the day of posting;

12.4.3 if sent by facsimile transmission and a valid transmission report confirming good receipt is generated, on the day of transmission if transmitted before 1800 hours (local time of recipient) on a Business Day or otherwise on the first Business Day after transmission,

but without prejudice to any provision of this Deed that refers to receipt of any Communication.

12.5 In proving service of the Communication, it shall be sufficient to show that:—

12.5.1 delivery by hand or by commercial courier was made;

12.5.2 the envelope containing the Communication was properly addressed and posted by first class, recorded delivery or special delivery post within the United Kingdom; or

12.5.3 the facsimile was despatched and a confirmatory transmission report received,

as the case may be.

13. Waiver

13.1 Save as expressly set out herein, no delay by or omission of either Party or any Associated Entity in exercising any right, power, privilege or remedy under this Deed shall operate to impair such right, power, privilege or remedy or be construed as a waiver of that right, power, privilege or remedy.

13.2 Any single or partial exercise of any such right, power, privilege or remedy shall not preclude any other or further exercise of that right, power, privilege or remedy or the exercise of any other right, power, privilege or remedy.

13.3 No waiver of any breach of this Deed shall (unless expressly agreed in writing) be construed as a waiver of a future breach of the same term or as authorising the continuation of the particular breach. No waiver of any breach of this Deed shall operate unless expressly made in writing.

14. Entire Agreement

14.1 Save as expressly provided herein, this Deed can be amended only by written deed between the Parties executed by their duly authorised representatives.

14.2 This Deed together with any other document expressed to be incorporated herein constitutes the entire agreement and understanding of the Parties with respect to its subject matter and supersedes and extinguishes any representations previously given or made other than those included in this Deed and any other document expressed to be incorporated herein.

14.3 Each Party acknowledges and agrees that on entering into this Deed it does not rely on, and shall have no remedy for misrepresentation in respect of, any warranty, representation, undertaking or assurance (whether negligently or innocently made) of any person unless expressly set out in this Deed as a representation, and that such liability in respect of any such warranty, representation, undertaking or assurance is expressly excluded.

14.4 Nothing in this Clause 14 limits or excludes any liability for fraud in relation to any such representation, warranty, undertaking or assurance.

15. Conflict

If there is any inconsistency between a provision in this Deed (for this purpose excluding the Schedules) and a provision in a Schedule, the provision in this Deed prevails to the extent of the inconsistency.

16. Execution in Counterparts

This Deed may be executed in any number of counterparts and by different parties in separate counterparts, any of which when so executed shall be deemed to be an original and all of which when taken together shall constitute one and the same Deed.

17. Governing Law

This Deed, and any non-contractual rights or obligations arising out of or in connection with it or its subject matter, shall be governed by and construed in accordance with English law. Any claim, dispute or difference of whatsoever nature arising out of or in connection with this Deed and any non-contractual rights or obligations arising out of or in connection with it or its subject matter shall be referred to the exclusive jurisdiction of the courts of England.

IN WITNESS WHEREOF the Parties have caused this Decommissioning Relief Deed to be executed as a deed on the date first above written.

Schedule 1
Reference Amounts

1. Definitions

Definitions used in the body of this Deed shall have the same meanings when used in this Schedule and unless otherwise stated references in this Schedule to Paragraphs are to paragraphs of this Schedule. In addition, the following terms and expressions shall bear the following meanings in Paragraph 2.3:—

"Net Cost" means the aggregate of the Claimant's share of Decommissioning Expenditure and in calculating Net Cost there shall be deducted:—

(i) receipts from decommissioning, including any actual salvage value;

(ii) Tax allowances available to the Claimant in respect of Decommissioning Expenditure; and

(iii) any payments due under this Deed;

"Net Revenues" means the aggregate of the Claimant's share of:—

(a) the sales value of petroleum produced and delivered or appropriated from the Field; and

(b) the proceeds of sale of any surplus Relevant Property sold prior to the date on which the final Decommissioning Expenditure in relation to the relevant decommissioning activity has been incurred; and

(c) the amount or value of any tariffs or other income received or receivable from the owners of other fields arising out of the provision of services utilising the Relevant Property under transportation, processing and other agreements,

and in calculating Net Revenues there shall be deducted:—

(i) the costs attributable to the Net Revenues, including but not limited to operating and capital costs (other than Decommissioning Expenditure) and sales costs;

(ii) Tax, but taking account of Tax allowances and any Government grants, allowances or other assistance given in relation to the Relevant Property or the operation of the Relevant Property (other than any Tax allowances available to any person in respect of Decommissioning Expenditure and any payments due under this Deed).

2. General

2.1 Save as specifically set out in this Schedule, a Reference Amount shall be calculated by reference to Enactment Date Legislation. For the avoidance of doubt, where losses are carried back to Tax Periods ending before the Enactment Date, Tax Capacity shall be determined by reference to the legislation in force during those Tax Periods.

2.2 References in this Deed to any expenditure (including Decommissioning Expenditure) being "**incurred**" shall, except where reference is made in Schedule 4 to expenditure being "**actually incurred**", be construed as references to the same being recognised as incurred for the purposes of the relevant Tax under Enactment Date Legislation (regardless of when payment was actually made in respect of such expenditure). Notwithstanding the foregoing, the fact that Decommissioning Expenditure may have been met directly or indirectly by a third party shall not prevent it being Decommissioning Expenditure for the purposes of this Schedule, subject always to Clause 6 and to Paragraph 9.1.

2.3 Where there is an Imposition which requires the Claimant to incur Decommissioning Expenditure in respect of a Licence Interest Share which it acquired as the result of forfeiture under a joint operating agreement, unitisation agreement or similar agreement, the expenditure shall be treated as Imposition Decommissioning Expenditure if, and then only to the extent that, the Net Cost that the Claimant has incurred in respect of such Licence Interest Share exceeds the Net Revenues it has received in respect of such Licence Interest Share. To the extent that such Net Cost does not exceed such Net Revenues, the expenditure so incurred shall be treated as Ordinary Decommissioning Expenditure.

2.4 On no account shall any item be taken into account as an allowance in the calculation of Net Cost for the purposes of Paragraph 2.3 if it has already been taken into account in the calculation of Net Revenues, and vice versa.

3. Calculation of RFCT Reference Amount where there is no Imposition

3.1 In relation to Ordinary Decommissioning Expenditure and subject to the remaining sub-paragraphs of this Paragraph 3, the RFCT Reference Amount for a Tax Period shall be equal to the amount of RFCT Relief or CT Relief that would under Enactment Date Legislation have arisen to the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) in all Tax Periods ending prior to the date of the Claim in respect of allowable Decommissioning Expenditure.

3.2 For the purposes of this Paragraph 3, allowable Decommissioning Expenditure means Ordinary Decommissioning Expenditure incurred by the Claimant in the relevant Tax Period and allowable Deductible Expenditure means Deductible Expenditure incurred by the Claimant in the relevant Tax Period.

3.3 This Paragraph 3.3 applies where there is no Imposition because the Claimant is an affiliate of a Defaulting Party.

3.3.1 The RFCT Reference Amount of the Claimant in relation to the allowable Decommissioning Expenditure incurred by the Claimant which would be Imposition Decommissioning Expenditure but for the relationship between the Claimant and the Defaulting Party shall be the RFCT Reference Amount which would have applied to the Defaulting Party if the Defaulting Party had been a party to this Deed instead of the Claimant and had incurred the Decommissioning Expenditure.

3.3.2 Where (i) the Claimant makes a Claim on the basis set out in this Paragraph 3.3, (ii) one or more claimants under this Deed or Similar Deeds ("**Other Claimants**") make or may be entitled to make claims on a similar basis in relation to the same Defaulting Party and (iii) the Decommissioning Expenditure which is or would be the subject of that Claim and such other claim or claims exceeds the Tax Capacity of the Defaulting Party, the provisions of Paragraphs 8.2 to 8.4 shall apply in relation to this Paragraph 3.3.2 as they apply in relation to Paragraph 8.1.

3.4 For the purposes of assessing the RFCT Relief that would arise in respect of allowable Decommissioning Expenditure under Enactment Date Legislation, any Difference Payment payable under Clause 5.2.3 (before any reduction of such Difference Payment under Clause 5.3) shall be treated as profits chargeable to Ring Fence Corporation Tax under Enactment Date Legislation.

3.5 To the extent that in determining the amount of RFCT Relief that would arise under Paragraph 3.1 a Claimant has insufficient Tax Capacity to treat as relievable all of its allowable Decommissioning Expenditure because that Tax Capacity has already been reduced as a result of the Claimant's incurring Imposition Decommissioning Expenditure or claiming relief for a loss made up of Imposition Decommissioning Expenditure pursuant to the provisions of Part 5 of CTA 2010, the RFCT Reference Amount for the relevant Tax Period shall be increased by the amount of additional RFCT Relief or CT Relief that the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) would have received in respect of allowable Decommissioning Expenditure under this Paragraph 3.5 had it not previously (or in the same Tax Period) incurred such Imposition Decommissioning Expenditure or claimed relief for such a loss.

3.6 If a Claimant has insufficient Tax Capacity to treat as relievable all of its allowable Deductible Expenditure because that Tax Capacity has already been reduced as a result of the Claimant's incurring Imposition Decommissioning Expenditure or claiming relief for a loss made up of Imposition Decommissioning Expenditure pursuant to the provisions of Part 5 of CTA 2010, the RFCT Reference Amount for the relevant Tax Period shall be, or be increased by, an amount equal to any reduction in liability to RFCT or repayment of RFCT or CT which the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) would have secured in respect of allowable Deductible Expenditure but for such insufficiency of Tax Capacity, to the extent that the insufficiency has not already been taken into account under Paragraph 3.5 or this Paragraph 3.6.

4. Calculation of SC Reference Amount where there is no Imposition

4.1 In relation to Ordinary Decommissioning Expenditure and subject to the remaining sub-paragraphs of this Paragraph 4, the SC Reference Amount for a Tax Period shall be equal to the amount of SC Relief that would under Enactment Date Legislation have arisen to the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) in all Tax Periods ending prior to the date of the Claim in respect of allowable Decommissioning Expenditure.

4.2 For the purposes of this Paragraph 4, allowable Decommissioning Expenditure means Ordinary Decommissioning Expenditure incurred by the Claimant in the relevant Tax Period and allowable Deductible Expenditure means Deductible Expenditure incurred by the Claimant in the relevant Tax Period.

4.3 The following provisions shall be applied when calculating the SC Relief for the purposes of Paragraph 4.1:—

4.3.1 where the profits against which the Decommissioning Expenditure is set were subject to a rate of Supplementary Charge greater than 20%, such profits shall be treated as relieved at a rate equal to the lower of:—

(a) the rate of Supplementary Charge to which they were subject; and

(b) a rate of 20% plus (i) in cases where the rate of Ring Fence Corporation Tax to which such profits were subject was less than 30%, the number of percentage points by which that rate was less than 30%, or (ii) in other cases, nil;

4.3.2 where such profits were subject to a rate of Supplementary Charge at or less than 20%, such profits shall be treated as relieved at that rate.

4.4 This Paragraph 4.4 applies where there is no Imposition because the Claimant is an affiliate of a Defaulting Party.

4.4.1 The SC Reference Amount of the Claimant in relation to the allowable Decommissioning Expenditure incurred by the Claimant which would be Imposition Decommissioning Expenditure but for the relationship between the Claimant and the Defaulting Party shall be the SC Reference Amount which would have applied to the Defaulting Party if the Defaulting Party had been a party to this Deed instead of the Claimant and had incurred the Decommissioning Expenditure.

4.4.2 Where (i) the Claimant makes a Claim on the basis set out in this Paragraph 4.4, (ii) one or more claimants under this Deed or Similar Deeds ("**Other Claimants**") make or may be entitled to make claims on a similar basis in relation to the same Defaulting Party and (iii) the Decommissioning Expenditure which is or would be the subject of that Claim and such other claim or claims exceeds the Tax Capacity of the Defaulting Party, the provisions of Paragraphs 8.2 to 8.4 shall apply in relation to this Paragraph 4.4.2 as they apply in relation to Paragraph 8.1.

4.5 For the purposes of assessing the SC Relief that would arise in respect of allowable Decommissioning Expenditure under Enactment Date Legislation, any Difference Payment payable under Clause 5.2.3 (before any reduction of such Difference Payment under Clause 5.3) shall be treated as profits chargeable to Supplementary Charge under Enactment Date Legislation.

4.6 To the extent that in determining the amount of SC Relief that would arise under Paragraph 4.1 a Claimant has insufficient Tax Capacity to treat as relievable all of its allowable Decommissioning Expenditure because that Tax Capacity has already been reduced as a result of the Claimant's incurring Imposition Decommissioning Expenditure or claiming relief for a loss made up of Imposition Decommissioning Expenditure pursuant to the provisions of Part 5 of CTA 2010, the SC Reference Amount for the Tax Period shall be increased by the amount of additional SC Relief that the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) would have received in respect of allowable Decommissioning Expenditure under this Paragraph 4.6 had it not previously (or in the same Tax Period) incurred such Imposition Decommissioning Expenditure or claimed relief for such a loss.

4.7 If a Claimant has insufficient Tax Capacity to treat as relievable all of its allowable Deductible Expenditure because that Tax Capacity has already been reduced as a result of the Claimant's incurring Imposition Decommissioning Expenditure or claiming relief for a loss made up of Imposition Decommissioning Expenditure pursuant to the provisions of Part 5 of CTA 2010, the SC Reference Amount for the Tax Period shall be, or be increased by, an amount equal to any reduction in liability to Supplementary Charge or repayment of Supplementary Charge which the Claimant (or another party pursuant to the provisions of Part 5 of CTA 2010) would have secured in respect of allowable Deductible Expenditure but for such insufficiency of Tax Capacity, to the extent that the insufficiency has not already been taken into account under Paragraph 4.6 or this Paragraph 4.7.

5. Calculation of PRT Reference Amount

5.1 In relation to Ordinary Decommissioning Expenditure and subject to Paragraph 5.4, the PRT Reference Amount for a Tax Period shall be equal to the amount of PRT Relief that would arise to the Claimant in respect of the relevant Field in that Tax Period and all earlier Tax Periods if Ordinary Decommissioning Expenditure incurred by the Claimant in those Tax Periods were set against Available Profits for those Tax Periods, applying Enactment Date Legislation. If a default has occurred and so section 84(2) FA 2013 applies, the PRT Reference Amount shall also include the amount of PRT Relief in respect of such Ordinary Decommissioning Expenditure that would have arisen to any of the Claimant's predecessors in title under Enactment Date Legislation but for the application of that section.

5.2 In relation to Imposition Decommissioning Expenditure, the PRT Reference Amount for a Tax Period shall be equal to the amount of PRT Relief that would arise in respect of the relevant Field in that Tax Period and all earlier Tax Periods, applying Enactment Date Legislation, if Imposition Decommissioning Expenditure incurred by the Claimant in those Tax Periods were set against Remaining Available Profits for those Tax Periods of the Claimant and its predecessors in title (whether or not still in existence) or the Defaulting Party and its predecessors in title (whether or not still in existence), at the option of the Claimant in accordance with Clause 6.1.4(b). For the purposes of this calculation:—

5.2.1 any Ordinary Decommissioning Expenditure shall be taken into account in accordance with Paragraph 5.1 before any Imposition Decommissioning Expenditure is taken into account in accordance with this Paragraph 5.2; and

5.2.2 **"Remaining Available Profits"** are so much of the Available Profits as (i) are not and have not been otherwise taken into account in accordance with Paragraph 5.1, or under a provision equivalent to Paragraph 5.1 or to this Paragraph 5.2 in any Similar Deed, and (ii) are not and have not been the subject of a claim for relief by any other person.

5.3 If PRT shall have been abolished, then the last Tax Period for which PRT was chargeable shall be taken as being the relevant Tax Period for the purposes of applying Paragraphs 5.1 and 5.2 and the PRT Reference Amount shall be determined by reference to the PRT Relief that would have arisen to the Claimant if the Decommissioning Expenditure had been incurred in that Tax Period.

5.4 Where there is no Imposition because the Claimant is an affiliate of a Defaulting Party, the Decommissioning Expenditure incurred by the Claimant which would be Imposition Decommissioning Expenditure but for the relationship between the Claimant and the Defaulting Party shall nevertheless be treated as Imposition Decommissioning Expenditure for the purposes of calculating the PRT Reference Amount pursuant to this Paragraph 5. The HMRC Certificate submitted by the Claimant in accordance with Clause 6.1.4(b) in respect of the relevant Claim shall be that of the Defaulting Party, but no account shall be taken of any PRT Relief that would have arisen to a predecessor in title of the Defaulting Party.

5.5 For the purposes of calculating PRT Relief where Imposition Decommissioning Expenditure has been incurred by the Claimant in respect of any Field, it shall not be required in respect of such expenditure to make use of any ability to set off an unrelieved field loss against the profits earned in respect of any other Field before making a Claim.

6. Calculation of RFCT Reference Amount in an Imposition

The RFCT Reference Amount for any Tax Period in respect of Imposition Decommissioning Expenditure incurred by the Claimant in that period shall be calculated by multiplying that expenditure by thirty per cent (30%).

7. Calculation of SC Reference Amount in an Imposition

The SC Reference Amount for any Tax Period in respect of Imposition Decommissioning Expenditure incurred by the Claimant in that period shall be calculated by multiplying that expenditure by twenty per cent (20%).

8. Calculation of PRT Reference Amount in an Imposition: Multiple Claimants

8.1 This Paragraph 8 shall apply where (i) the Claimant makes a Claim which relies on the Tax Capacity of a Defaulting Party (including where relevant the Tax Capacity of any of its predecessors in title), (ii) one or more claimants under Similar Deeds ("**Other Claimants**") make or may be entitled to make claims which also rely on that Tax Capacity and (iii) the Decommissioning Expenditure which is or would be the subject of that Claim and such other claim or claims exceeds that Tax Capacity.

8.2 Upon becoming aware that the circumstances described in Paragraph 8.1 exist, the Government Counterparty shall notify the Claimant and shall use reasonable endeavours to identify any potential Other Claimants (and the Claimant shall render such reasonable assistance as may be requested for such purpose).

8.3 The relevant Tax Capacity shall be apportioned between the Claim and those other claims or potential claims so that the aggregate entitlement available under this Deed and the other deeds referred to in Paragraph 8.1 (taken together) is shared between the Claimant and the Other Claimants (including those who have not yet made a related claim) pro rata according to the amount of the Decommissioning Expenditure attributable to the Defaulting Party that is borne by them, unless the Government Counterparty, the Claimant and the Other Claimants agree an alternative apportionment.

8.4 Upon the final determination of the apportionment of the relevant Tax Capacity in accordance with Paragraph 8.3, the Government Counterparty shall issue to the Claimant and the Other Claimants notices setting out the amount of the relevant Tax Capacity respectively apportioned to them (each an "**Apportionment Notice**"). The amount of Tax Capacity stated in the Apportionment Notice issued to the Claimant shall be final and binding for the purposes of this Deed.

9. Other Issues

9.1 Decommissioning Expenditure shall not give rise to a Difference Payment in respect of:—

9.1.1 Ring Fence Corporation Tax (an "**RFCT Difference Payment**") under Clause 5.2.1, if and to the extent that (i) a person other than the Claimant has obtained an RFCT Difference Payment under this Deed or a Similar Deed by virtue of that expenditure, or (ii) any person has obtained RFCT Relief in respect of that expenditure (whether directly or pursuant to the provisions of Part 5 of CTA 2010);

9.1.2 Supplementary Charge (an "**SC Difference Payment**") under Clause 5.2.2, if and to the extent that (i) a person other than the Claimant has obtained an SC Difference Payment under this Deed or a Similar Deed by virtue of that expenditure, or (ii) any person has obtained SC Relief in respect of that expenditure (whether directly or pursuant to the provisions of Part 5 of CTA 2010); or

9.1.3 PRT (a "**PRT Difference Payment**") under Clause 5.2.3, if and to the extent that (i) a person other than the Claimant has obtained a PRT Difference Payment under this Deed or a Similar Deed by virtue of that expenditure, or (ii) any person has obtained PRT Relief in respect of that expenditure.

9.2 For the avoidance of doubt, but subject to Clause 6.10, nothing in this Deed shall apply to prevent a Claim, in circumstances where the Claimant shall have received reimbursement of Decommissioning Expenditure from a trustee under decommissioning security arrangements or from a bank, insurance company or similar entity pursuant to a call on a letter of credit or bond in favour of the Claimant or any similar arrangement, merely because such trustee, bank, insurance company or similar entity has claimed a relief from Tax in respect of such payment.

9.3 Any Reference Amount calculated under Paragraph 3.1 or Paragraph 6.1 shall be increased by the amount of any Tax on Decommissioning Expenditure (not being a Tax in existence on the Enactment Date) which is payable by a Claimant in respect of the Decommissioning Expenditure taken into account in calculating such Reference Amount, less the amount of any reduction in Ring Fence Corporation Tax, Supplementary Charge or PRT arising as a result of bearing such Tax.

Schedule 2
Contact Details

For the Government Counterparty:

Director of Business and International Tax, HM Treasury, 1 Horse Guards Road, London SW1A 2HQ

copied to:

Deputy Director Oil and Gas, HMRC, LBS Oil & Gas, 5th Floor, SW Bush House, Strand, London WC2B 4RD

For the Company:

[ ]

Schedule 3
HMRC Certification Process

1. HMRC shall:—

1.1 on the request of the Company or any Associated Entity which is a participator in a Field, provide a certificate showing the Available Profits against which Decommissioning Expenditure might be set, and the rate(s) of relief which would be applied to such Decommissioning Expenditure, if such Decommissioning Expenditure as could not be relieved against current period profits of the participator arising from the Field were to be carried back as a loss against the Tax Capacity of the participator and its predecessors in title in respect of all or part of its Licence Interest Share in such Field;

1.2 on the request of any Associated Entity where the Company or another Associated Entity is a participator in a Field, provide a certificate showing the Available Profits against which Decommissioning Expenditure might be set, and the rate(s) of relief which would be applied to such Decommissioning Expenditure, if such Decommissioning Expenditure as could not be relieved against current period profits of the participator arising from the Field were to be carried back as a loss against the Tax Capacity of the participator and its predecessors in title in respect of all or part of its Licence Interest Share in such Field;

1.3 on the request of the Company or any Associated Entity which may incur Imposition Decommissioning Expenditure if a third party fails to incur the Decommissioning Expenditure associated with its Licence Interest Share, provide a certificate showing the Available Profits against which Decommissioning Expenditure might be set, and the rate(s) of relief which would be applied to such Decommissioning Expenditure, if such Decommissioning Expenditure as could not be relieved against current period profits of the third party arising from the Field were to be carried back as a loss against the Tax Capacity of the third party concerned and its predecessors in title in respect of all or part of its Licence Interest Share in such Field; and

1.4 on the request of the Company or any Associated Entity which has incurred or reasonably expects that it may incur Imposition Decommissioning Expenditure, provide a certificate showing the Available Profits against which Decommissioning Expenditure might be set, and the rate(s) of relief which would be applied to such Decommissioning Expenditure, if such Decommissioning Expenditure as could not be relieved against current period profits of the relevant Defaulting Party arising from the Field were to be carried back as a loss against the Tax Capacity of the Defaulting Party and its predecessors in title in respect of all or part of its Licence Interest Share in such Field.

Such certificate shall bear the date of its issue and shall also indicate the most recent Tax Period for the relevant participator and its predecessors in title which has been agreed with HMRC and which Tax Periods remain open. In relation to open periods the certificate shall specify the Available Profits identified in the tax return or returns submitted by the relevant participator and its predecessors in title.

2. HMRC shall provide confirmations and issue further certificates in accordance with the provisions of this Paragraph 2.

2.1 Where a certificate has been issued in accordance with Paragraph 1, the certificate holder may no sooner than six months thereafter (and subsequently at intervals of no less than six months) submit that certificate (or any further certificate issued in accordance with this Paragraph 2) to HMRC together with a request that HMRC confirms whether the matters stated on such certificate remain accurate and, if not, for HMRC to cancel that certificate and issue a further certificate on the same terms containing the updated information.

2.2 If a certificate holder considers that its circumstances are such that it will require its certificates to be verified and (if necessary) reissued on a more frequent basis, then it may so notify HMRC setting out its reasons and providing any necessary supporting evidence. HMRC shall give due and proper consideration to all such requests and shall comply with them to the extent that they are reasonably made, provided that any such request must be founded on extraneous circumstances affecting the certificate holder or the Field in question rather than convenience or a desire to optimise cash flow.

3. A certificate issued in accordance with this Schedule 3 shall take account of any unrelieved field losses of the relevant participator from any other Field already carried back and set off against the profits earned by the participator in the Field which is the subject of the certificate, but shall not take account of the ability of the participator to carry back any unrelieved field losses accruing to it from the Field which is the subject of the certificate against profits in another Field in which it (or an affiliate) is a participator.

4. In preparing a certificate for the purposes of this Schedule 3, HMRC shall take no account of the fact that a participator or its predecessor in title may have been dissolved.

5. The Government Counterparty shall procure that HMRC complies with the provisions of this Schedule 3.

Schedule 4
Principles supplementary to Clause 8

Ordinary course decommissioning

1. The Company or an Associated Entity undertakes or procures decommissioning in the ordinary course for the purposes of Clauses 8.5 and 11.2:—

   1.1 where the decommissioning relates to plant or machinery in which the Company or an Associated Entity has a beneficial interest, to the extent that the decommissioning cost relates to that beneficial interest);

   1.2 where under arm’s length commercial arrangements it has agreed to be responsible for other decommissioning costs, which might include (but are not limited to):—

      (a) sole risk situations;

      (b) carried interests;

      (c) a user Field agreeing to be responsible for the cost of decommissioning particular plant or machinery installed for its benefit on a host platform or pipeline;

      (d) arrangements under which it disposes of an interest in a Field (whether by way of sale, lease, farm-in, exchange or otherwise) but retains an obligation to pay for all or part of the decommissioning of that Field to the extent of that interest (whether or not allied to an obligation to take a re-transfer of the relevant interest);

      (e) arrangements under which it ceases to benefit from production as a result of a withdrawal but retaining a liability for decommissioning commensurate with its former interest; or

      (f) allocation or substitution arrangements; and

   1.3 where it is required by statute, or by arm’s length commercial arrangements entered into in the ordinary course, to incur Decommissioning Expenditure as the result of the failure of another party to undertake decommissioning work or incur Decommissioning Expenditure which that party was required, by statute or by contractual arrangements entered into in the ordinary course, to undertake or incur,

   and for the avoidance of doubt decommissioning in the ordinary course may involve incurring either Ordinary Decommissioning Expenditure or Imposition Decommissioning Expenditure (or both).

Principles

2. There should not be arrangements which have as their main purpose or one of their main purposes enabling Decommissioning Expenditure to be treated as Imposition Decommissioning Expenditure.

3. Relief for Decommissioning Expenditure is to be given, and any Difference Payment is to be made, only to the extent that:—

   (a) Decommissioning Expenditure that is treated as incurred is actually incurred;

   (b) the decommissioning to which the Decommissioning Expenditure relates has been carried out;

   (c) the Decommissioning Expenditure relates solely to the decommissioning carried out (and not for example to financing costs that the person undertaking or procuring the decommissioning may incur); and

   (d) the amount of Decommissioning Expenditure incurred is proportionate to the decommissioning carried out in the relevant Tax Period and has not been inflated with a view to obtaining increased Decommissioning Relief or an Entitlement.

4. There should not be arrangements which have as their main purpose or one of their main purposes securing relief for Decommissioning Expenditure or a Difference Payment sooner than it would have been secured in the absence of the arrangements.

5. In respect of any given item of expenditure:—

   (a) to the extent that relief is secured under the tax code, no Difference Payment should be obtained under this Deed (by the same or any other person);

   (b) to the extent that a Difference Payment is made and retained under this Deed, no relief should be secured and retained under the tax code (by the same or any other person); and

   (c) any relief should be secured, or any Difference Payment should be made, once only.

6. Except as expressly stated otherwise herein, a Claim should only be made under this Deed after the person incurring the Decommissioning Expenditure has sought to obtain any Decommissioning Relief available under Current Legislation.

Executed as a deed by
THE LORDS COMMISSIONERS TO HER MAJESTY'S TREASURY

Signature	Full Name

In the presence of:

Witness Signature	Witness Full Name
Witness Address	Witness Occupation

Signature	Full Name

In the presence of:

Witness Signature	Witness Full Name
Witness Address	Witness Occupation

Executed as a deed by
[COMPANY]

[Director/Authorised Signatory] Signature	Full Name

In the presence of:

Witness Signature	Witness Full Name
Witness Address	Witness Occupation

Executed as a deed by	)	
[LIMITED]	)	
on being signed by its duly authorised attorney	)	……………………………………
…………………………………	)	Duly Authorised Attorney
in the presence of:	)	

Signature of witness: ……………………………………

Name: ……………………………………

Address: ……………………………………

……………………………………

Occupation: ……………………………………

Executed as a deed by	)	
[LIMITED]	)	……………………………………
on being signed by:	)	Director
…………………………………………	)	
and ……………………………………	)	……………………………………
		Director/Secretary

INTERNATIONAL REPORT—WORLD BANK

1. Background and History

Since its inception in 1944, the World Bank has expanded from a single institution to a closely associated group of five development institutions with more than 10,000 employees in more than 120 offices worldwide. The World Bank mission evolved from the International Bank for Reconstruction and Development (IBRD) as facilitator of post-war reconstruction and development to the present-day mandate of worldwide poverty alleviation. World Bank coordinates with their affiliate, the International Development Association, and other members of the World Bank Group: the International Finance Corporation (IFC), the Multilateral Guarantee Agency (MIGA), and the International Centre for the Settlement of Investment Disputes (ICSID).

Since early 2009, the World Bank has been leading a "Toward Sustainable Decommissioning of Oil Fields and Mines Initiative" (Initiative) to assist international governments in oil and gas and/or mining resource-rich, developing countries in the process of undertaking earlier, more systematic, comprehensive, and responsive planning of the decommissioning and closure phase of mining and oil and gas production operations. The Initiative falls under the environmental pillar of the Petroleum & Governance Initiative (PGI), a collaboration between the World Bank and the Government of Norway.

A Toolkit "Toward Sustainable Decommissioning of Oil Fields and Mines: A Toolkit to Assist Government Agencies" covering the essential economic, social, environmental, regulatory, and technical aspects of decommissioning, was prepared and shared with stakeholders. This Toolkit is a living document or tool designed to increase the level of awareness on decommissioning and closure issues. It serves as guidance to government authorities, institutions, and regulatory agencies in oil and gas/mining resource-rich, developing countries seeking to establish or improve closure and decommissioning programs for the extractives sectors (World Bank 2014). The Toolkit is available at the World Bank's web page. (http://go.worldbank.org/5IVXTJV1Y0.)

2. Regulatory Structure

This Toolkit is more relevant when applied from the earliest phases of a project's life-cycle. However, it is recognized that many countries may have mines and oil fields nearing closure in the next several years. In such cases, the approach and tools presented remain valid, but much of the material relating to the earlier phases may not be directly applicable to late stage projects. Consequently, more effort may be required to meet the proposed guidance. The applicability of the guidance provided in the Toolkit is neither prescriptive nor mandatory, nor does it imply any precedence over existing in-country laws or regulations. However, in the absence of other guidance, it can be used as a "roadmap" for the development of an effective general regulatory approach to sustainable decommissioning and closure.

3. Bonding/Financial Commitments

The Toolkit provides information on how to set up a bonding/financial regulatory framework. Tool 1 Policy and Regulatory Framework: aims to delineate the steps for an enhanced policy and regulatory framework, and provides a platform for the implementation of the remaining tools.

Given the unique characteristics of the decommissioning and closure situation, it is necessary to thoroughly understand the range of financial surety instruments available and propose, establish, and agree with the appropriate mechanism with the facility owner on a case-by-case basis. The following overview of financial surety instruments has been taken from previous work done by the Oil, Gas, and Mining Policy Division of the World Bank, and aims to provide guidance on the understanding of the instruments. It is recognized that financial surety instruments come at significant cost to owner companies; however, it is important that an individual government has surety that financial resources will be available for decommissioning and closure, and can minimize situations where general taxpayer funds are used. The tax deduction on these instruments varies by country, which should be made clear to owner companies. The following summarizes some key advantages and disadvantages offered by the various instruments.

3.1 Trust Fund

A trust fund, which may also be known as a mining reclamation trust or a qualifying environmental trust is an agreement between a trust company and the owner company for the sole purpose of funding the rehabilitation or land reclamation of a site. In addition to a trust fund, there should be a signed agreement between the owner company and the government, administered by the trust company, that stipulates the owner company's responsibility with regard to the trust fund. This agreement should specify that the trust fund is to provide financial security for the rehabilitation or land reclamation costs for a particular site, the total amount required, and an outline schedule of payments. If the payments are not consistently made to a Trust Fund, and the owner company fails to provide an acceptable alternative form of surety, then the government should have the option of drawing the full amount of the fund. The owner company should be responsible for fees and charges associated with drawing the full amount of the fund.

3.2 Insurance Policy

There is a wide range of insurance options. Recently American International Group (AIG) began to sell reclamation policies that consider both land reclamation and post-closure activities by using a finite instrument that attaches environmental insurance to a financial assurance package. This policy supports reclamation obligations issued on bonds.

General forms of insurance, such as premium financing, commercial general liability, and professional indemnity, do not typically insure environmental liabilities. One major advantage of an insurance policy is that premiums are usually tax deductible. Payments are available for land reclamation work via the use of insurance claims.

In the US, AIG has a custom designed product that combines three products: a conventional surety bond, accumulation of cash within the policy, and insurance protection for overruns and changing requirements. This product is based on the rehabilitation plans and projected costs, the credit worthiness of the owner company, and the market value of the mine assets. From the funds deposited, the insurance company issues the required security bonds to the government and pays the actual rehabilitation costs. At the end of project life, if there is a surplus in the account, it goes back to the owner company. If there is a deficit due to additional regulatory reclamation changes that translate into an insurance claim, then the insurance company pays. For the placement of the insurance policy, the insurance company will conduct an exhaustive independent technical review covering permit obligations and land reclamation costs.

3.3 Third-Party Guarantees

Third-party guarantees, such as surety bonds, insurance bonds, or performance bonds, are agreements between an insurance company and an owner company to provide funds to a third party under certain circumstances. In this instance, the third party is the relevant government department. A bond will include the terms and conditions of the agreement between the owner company and the government, with reference to the rehabilitation program, the agreed costs, and the conditions for the release of the bond. Any changes to a bond require the consent of all parties involved. A bond is issued by an insurance company that should be licensed under the relevant legislation. It is issued for a specific time period and can be renewed for further time periods based on a credit review of the owner company. During this process, the amount of a bond can be increased or decreased depending on the amendments to the rehabilitation program. If a bond is not renewed, and the owner company fails to provide an acceptable alternative form of surety, then the government has the option of drawing the full amount. The owner company should be responsible for all fees and charges associated with a bond.

3.4 Letter of Credit

An irrevocable letter of credit, also known as a bank guarantee, is an unconditional agreement between a bank and owner company in order to provide funds to a third party on demand. In this instance, the third party is the relevant government department. A letter of credit includes the terms and conditions of the agreement between the owner company and the government, with reference to the rehabilitation program and the agreed costs. Any changes to the letter of credit require the consent of all parties involved.

To obtain a letter of credit, the owner company will have to demonstrate to the bank that provisions have been made for the rehabilitation of the site and that it has sufficient funds or liquidity to cover the costs. A letter of credit is usually issued for 1 year and renewed annually following a review of rehabilitation requirements and costs. If the bank, for any reason, will not renew a letter of credit, and the owner company fails to provide an acceptable alternative form of surety, then the government can request payment for the full outstanding amount of a letter of credit.

The government will usually specify from which banks it will accept a letter of credit. The annual cost of a letter of credit ranges from 0.5 to 9 percent of the guaranteed amount, depending on the owner company's credit rating. The funds held in a letter of credit do not generate any interest.

3.5 Cash Deposit

A deposit can be made for a financial surety as cash, a bank draft, or a certified check. The funds should be placed in a special purpose account under the management of the financial institution with the government and company holding joint signatory powers. Alternatively, the cash can be used to purchase a certificate of deposit, which can be pledged to the relevant government agency. Most commercial banks would charge nominal fees for setting up such accounts, and the money would generate interest, which would accrue to the fund.

3.6 Other Options

Other options include company guarantees, pledge of assets, and sinking funds. A company guarantee, which may also be called a corporate financial test, a balance sheet test, or a self-guarantee, is based on an evaluation of the assets and liabilities of the company and its ability to pay the total rehabilitation costs. A company guarantee requires a long history of financial stability, a credit rating from a specialized credit rating service, and at least an annual financial statement prepared by an accredited accounting firm.

In some jurisdictions, a pledge of assets is an acceptable form of financial surety. This takes the form of surplus equipment and scrap metal that remains at site after operations have ceased. The surplus equipment includes stationary equipment and buildings. The scrap metal includes metal debris produced during site demolition and the cleanup process.

If a pledge of assets is being used as a financial surety, several factors should be considered. The assets must be free and clear of encumbrances, fixed and not easily moved, not contaminated, and there must be a market demand for the assets. The value estimation must be carried out by a third party, should include the cost of retrieval and transportation from the site to the marketplace, and must be recalculated periodically. However, this is generally viewed as a high-risk form of financial surety and is not accepted in many countries.

Sinking funds make it possible for corporations to set aside money for future capital expenses. These funds are governed by special provisions stated in a bond's indenture. An indenture is a legal contract between two parties. A bond indenture, also known as a deed of trust or a trust indenture, is a legal document that outlines and describes key terms.

3.7 Socioeconomic Considerations

Social legacies, a fund that contributes financial resources to provide long-term sustainable support for local communities, are often not captured in financial assurance tools and planning. However, because they can have significant effects (positive or adverse) on communities and societies and on the reputation of companies, integrating social considerations into closure planning is crucial to sustainable decommissioning and closure.

4. Bonding and Financial Security Conditions

The Toolkit emphasizes the importance for governments to monitor compliance with regulations and requirements during the planning and implementation of decommissioning and closure activities for mines and oil fields. This tool will: emphasize the importance of government-led performance monitoring and enforcement mechanisms; outline key steps that governments or responsible authorities can use to guide the development or enhancement of monitoring and enforcement of decommissioning and closure goals; and provide relevant background, guidance, and sources of additional information.

SOURCES CITED

World Bank. 2014. Sustainable Decommissioning of Oil Fields and Mines. Web page. located at: http://go.worldbank.org/5IVXTJV1Y0

CANADA FEDERAL JURISDICTIONAL AREAS

1. Background and History

1.1 Hydrocarbon Resources

Canada is rich in oil and natural gas and currently has the world's third largest proven reserves of crude oil. The vast majority of Canada's proven oil and gas reserves and production facilities are located within the Province of Alberta. Discoveries of oil and gas in Alberta (in particular, in the Athabasca oil sands) have made Alberta the largest oil and gas producing region in North America. In 2011, Alberta produced 1.7 million barrels of oil per day, and it is estimated that this figure will rise to more than 3 million barrels per day by 2020.

Canada is the world's fifth largest producer of natural gas, with production of 13.9 billion cubic feet per day (CAPP 2014).

1.2 Mineral Resources

Canada is an important source of mineral products that include precious metals (gold, silver, platinum) and diamonds, base metals (iron, copper, lead, zinc, nickel), energy minerals such as coal and uranium, and industrial minerals (limestone, rock salt, potash, gypsum). Mining is one of Canada's primary industries and involves the extraction, refining, and/or processing of economically valuable rocks and minerals. There are some 800 mines across the country which directly employ more than 363,000 workers. Canada ranks first in the world for the production of potash and uranium and among the top five for the production of nickel and diamonds. Canada's total estimated mineral production in 2012 topped $46.8 billion, representing 3.4 percent of the country's gross domestic product (Mining Association of Canada 2014).

2. Regulatory Structure

2.1 Federal Government's Jurisdiction

Canada's Constitution Act of 1982 divides legislative authority between the federal Parliament and the provincial legislatures. Under the Act, Canada's provincial governments are responsible for the management of natural resources within their jurisdiction. Provincial governments are responsible for regulating the exploration, development, and extraction of mineral and oil and gas resources and the construction, management, reclamation, and close-out of mine and oil and gas sites within their jurisdiction.

The federal government's involvement in the regulation of mining operations is limited to the Territory of Nunavut and is specific in nature. It includes uranium exploration and disposal, mineral activities related to federal Crown corporations, and mineral activities on federal lands and offshore areas (Government of Canada 2013b).

The federal government is also responsible for regulating the construction and operation of interprovincial and international oil and gas pipelines and for the exploration, production, processing, and transportation of oil and gas in marine areas. These areas include the 'territorial sea' (12 nautical miles beyond the low water mark of the outer coastline) and the 'continental shelf' (beyond the territorial sea), and they do not include areas controlled by the provincial government (Natural Resources Canada 2014).

The federal government administers Crown land in the Canadian Territories (Northwest Territories, Nunavut, and Yukon) pursuant to the Territorial Lands Act recently revised in April 2014.

2.2 Regulatory Agencies

2.2.1 Aboriginal and Northern Development Canada

Aboriginal Affairs and Northern Development Canada (AANDC) administers Crown land in the Canadian Territories (Northwest Territories, Nunavut, and Yukon) pursuant to the Territorial Lands Act. AANDC manages surface activities on Crown lands in the Northwest Territories through the administration, regulation, inspection, and enforcement of renewable and non-renewable legislation. Crown lands and the federal department with administration and control of those lands are now defined in the exclusion list contained in the Northwest Territories Devolution Agreement.

The Resource and Land Management Directorate of AANDC supports environmental protection and economic development in the territory through the administration of surface and sub-surface rights on federal lands, the management of On-Reserve lands and environment, the administration of northern offshore oil and gas interests, and environmental assessments on federal lands.

2.2.2 National Energy Board

The National Energy Board (NEB) established under the National Energy Board Act (NEB Act of 1985) is an independent federal agency with responsibilities for regulating the construction and operation of interprovincial and international oil and gas pipelines, and oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements pursuant to the Canada Oil and Gas Operators Act of 1985 (COGOA). The NEB's regulatory oversight extends over 71,000 kilometres of pipeline that cross most of the country, and approximately 1,400 kilometres of international power lines (NEB 2014a).

The NEB's purpose is to promote safety and security, environmental protection, and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development, and trade.

2.3 Canada - Newfoundland and Labrador and Canada - Nova Scotia Offshore Petroleum Boards

The Canada - Nova Scotia and Canada - Newfoundland and Labrador Offshore Petroleum Boards are responsible for the exploration and development of the hydrocarbon resources in the offshore areas of Newfoundland and Labrador and Nova Scotia.

The Minister of Natural Resource Canada (NRCan) oversees the administration of the Atlantic Accord and the Atlantic Accord Implementation Acts of 1987, which applies to oil and gas activities of operators in the Newfoundland and Labrador and Nova Scotia offshore areas.

The Acts establish the Canada-Newfoundland Labrador Offshore Petroleum Board (C-NLOPB) and the Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) with responsibilities to oversee oil and gas operator's compliance with statutory provisions of the act and regulations.

The role of the Boards is to facilitate the exploration for and development of the hydrocarbon resources in the Newfoundland, Labrador, and Nova Scotia offshore areas in a manner that conforms to the statutory provisions for: worker safety; environmental protection and safety; effective management of land tenure; maximum hydrocarbon recovery and value; and benefits to the federal and provincial governments. While the legislation does not prioritize these mandates, worker safety and environmental protection will be paramount in all Board decisions.

2.4 Canadian Nuclear Safety Commission

The Canadian Nuclear Safety Commission (CNSC), established under the Nuclear Safety and Control Act of 2000 (NSCA), is responsible for regulating uranium mining. This Act provides the CNSC with the authority to regulate the development, production, and use of nuclear energy and the production, possession, and use of nuclear substances, prescribed equipment, and prescribed information in Canada.

The CNSC regulates the use of nuclear energy and materials to protect health, safety, security, and the environment; to implement Canada's international commitments on the peaceful use of nuclear energy; and to disseminate objective scientific, technical, and regulatory information to the public. The CNSC's regulatory framework consists of laws passed by Parliament that govern the regulation of Canada's nuclear industry, and regulations, licenses, and documents that the CNSC uses to regulate the nuclear industry.

3. Financial Securities

3.1 Financial Securities - Aboriginal and Northern Development Canada

The Mine Site Reclamation Policy for Nunavut released by the AANDC on July 29, 2002 is designed to provide a resource management tool to ensure that mining operations in Nunavut do not leave a legacy of environmental and human health hazards and a financial burden on the Canadian taxpayer. It provides certainty and clarity concerning the government's expectations on mine site reclamation.

The policy applies to new and existing mines, whether operating or not, with clearly identified owners/operators. It does not cover orphaned or abandoned sites, which fall under the proposed Policy on the Management of Contaminated Sites in Canada's North. The policy applies only to developed mines and to those mining-related activities that take place on mine sites. It does not apply to activities undertaken during the prospecting, exploration, or advanced exploration stages of the development of a mineral property.

The total financial security for final reclamation required at any time during the life of the mine should be equal to the total outstanding reclamation liability for land and water combined (calculated at the beginning of the work year, to be sufficient to cover the highest liability over that time period).

Estimates of reclamation costs, for the purposes of financial security, should be based on the cost of having the necessary reclamation work done by a third-party contractor if the operator defaults. The estimates should also include contingency factors appropriate to the particular work to be undertaken.

The recognized methodology for calculating reclamation costs, for the purposes of financial security, should be the RECLAIM or other appropriate model. Consideration should be given to alternate or innovative forms of security, such as mine reclamation trusts, provided that they meet certain criteria that protect the government's interests and objectives.

Financial security requirements related to reclamation should be clearly set out in water licenses, land leases, and other regulatory instruments, though there may be circumstances where security requirements may be more appropriately dealt with through an agreement.

Mining operators should be credited for approved progressive reclamation, and the value of financial security required should be adjusted in a timely fashion.

All proposals for a new mine must include a mine closure and reclamation plan. This is critical to the long-term future and environmental legacy of the development site. For greater efficiency, a plan should integrate the requirements associated with leasing surface rights and water licensing.

A key element of the mine closure and reclamation plan is the relationship between the closure and reclamation obligations, and the financial security provided to ensure the liability for reclamation remains with the mining company. There are a number of issues relating to financial security, as discussed below, which must be considered as part of this policy.

3.1.1 Forms of Security

Financial security for mine site reclamation for new mines must be readily convertible to cash. Such security must have the following basic criteria:

- Subject to applicable legislation and due process, it must provide the Crown with immediate, unconditional, unencumbered access to the full amount of the security.
- It must retain its full value throughout the life of the mine and, if applicable, beyond.
- It must remain beyond the control of the mining company or its creditors in the event of insolvency.

The Minister may consider new or innovative forms of security, such as reclamation trusts, provided that they meet the above criteria.

3.1.2 Progressive Reclamation

Ongoing reclamation throughout the life of the mine is preferable from both the environmental and financial liability perspectives. The financial security of a mining project will be adjusted to reflect progressive reclamation on the following basis:

- When ongoing reclamation work reduces the outstanding environmental liability, it will result in a reduction in the level of financial security required to be maintained.
- Credit for progressive reclamation work should be made in a timely fashion in accordance with authorities set out in the applicable legislation.
- The value of reclamation work will be based on generally accepted modelling (e.g., the RECLAIM model) and calculated as the difference between previous outstanding liabilities and estimates made of the remaining liability following the reclamation work (as opposed to actual costs, if actual costs do not fully reduce outstanding liability).
- The amount of financial security on deposit will normally increase proportionately as mining proceeds. Generally, this implies that, as the mine site grows, water usage increases and the cost to restore a site expands. Accordingly, reclamation costs are usually estimated to increase over the life of the mine. However, as reclamation work is performed, the environmental liability is reduced and the financial security required may decrease proportionately.
- If, during a specific period, the value of any progressive reclamation exceeds the value of new reclamation liability created through additional mining operations, AANDC would reduce the amount of security required through the surface lease and would support an application by the mining company to the Water Board to reduce the amount of the water license security accordingly.

- Progressive reclamation may not reduce the financial assurance required to zero. Sometimes, a residual amount is required to meet other licensing obligations.

3.1.3 Post-Closure Reclamation and Final Decommissioning

Near the end of production, when closure is anticipated, the most recent approved plan will be the basis for final decommissioning. As reclamation work is successfully completed and environmental liability is reduced, the amount of financial assurance required will be proportionately reduced and the surplus refunded.

The Minister may hold back an appropriate amount of financial assurance to cover future requirements for the site. In such cases, the mining company will be responsible for the care and maintenance of the site, but will also maintain a claim to any remaining financial assurance.

When the Minister is satisfied that the operator has met the requirements for decommissioning under the relevant legislation and that the objectives of the plan have been fully met, the Minister will provide the mining company with a written acknowledgement to that effect.

3.1.4 Transition Rules for Existing Mines

This policy covers existing mining operations. However, it is recognized that the status of reclamation planning and the degree of financial assurance in effect varies considerably from mine to mine. Therefore, the application of certain aspects of this policy will have to take into account the specific situation and issues of individual mines on a case-by-case basis.

For existing operations, the financial security provided to the Minister for reclamation obligations should be increased in increments to 100 percent coverage as soon as possible, but not later than the forecast life of the mine. Only when a mine operator could conclusively demonstrate that it was financially incapable of doing so and the Minister was satisfied that it was in the public's best interests would the Minister consider options relating to the form, amount, or schedule for the provision of financial security.

All new reclamation liabilities created by future operations would be subject to the same requirement to provide full security as new mines.

3.2 Bonding and Financial Responsibility Requirements for Offshore Oil and Gas-Canada-Nova Scotia and Canada-Newfoundland and Labrador Petroleum Offshore Boards

The C-NLOPB’s and the C-NSOPB’s Development Plan Guidelines require that Abandonment and Decommissioning (A & D) be assessed. The plan for A & D may be addressed in the conditional approval of the project.

Under the Petroleum Drilling Regulations, an operator must provide evidence of financial responsibility prior to drilling or re-entering a well. No authorization can be issued unless the Financial Responsibility Requirement (FRR) is addressed as provided in the FRR Guidelines. The operator must:

- Furnish evidence of financial responsibility in a form and in an amount satisfactory for the purpose of ensuring that the operator terminates the well and leaves the drill site in a satisfactory condition.
- Furnish evidence that the operator is financially able to meet any financial liability that may be incurred as a result of the drilling of a well or of any operation in the well.

3.2.1 Bonding Requirements for a Development or Production Work or Activity

The Boards require evidence of financial responsibility to be approved respecting the authorization of any work or activity relating to the abandonment of wells or the decommissioning of a production installation.

Evidence of financial responsibility includes a package of documentation submitted by the operator that is intended to apply to all authorizations contemplated for the entire development. This package must be submitted to the Board at least 30 days prior to anticipated work or activity. The operator should advise the Board of its proposals at least 9 months prior to the anticipated commencement of the first work or activity.

For a work or activity that would be considered as inherently or exclusively relating to development or production, there are two categories of evidence of financial responsibility, almost identical to those respecting drilling, which the operator must provide.

The first category of evidence submitted has the following characteristics. The purpose of the evidence would be to provide assurance to the Board that monies would be available to and accessible by the Board for the purpose of settling claims relating to: spills and debris (where such activity involved drilling or producing operations) and any cost or expenses incurred by or on behalf of the Board or Her Majesty, in properly terminating the work or activity and leaving the site in a condition satisfactory to the Board.

The aggregate amount and form of evidence required would be up to $100 million. In the event the work or activity involves drilling or producing operations, the requirements shall be the same as those set out above; or in the event that no drilling or producing operation is involved, the form of the evidence will depend upon the nature of the circumstances and the details respecting the work or activity. In that event, the form(s) shall be as approved by the Board on a case-by-case basis.

The second category of evidence submitted would have the following characteristics:

> “(i) The purpose of the evidence is not to demonstrate accessibility by the Board as above, but to demonstrate that the operator is able to meet *any financial liability* that may occur in conducting the

work or activity; (ii) The types and limits of financial liabilities for which the operator needs to provide evidence would include: in respect of removal of debris: up to 25% of the reinstatement cost of the property; in respect of liabilities to third parties: up to C$200 million; in respect of pollution clean-up: up to C$250 million. (iii) The evidence required for the above amounts may be provided in the form of insurance; an audited financial statement; corporate guarantee from a third party, including an affiliate; letter of credit or indemnity bond; any other form acceptable to the Board; or a combination of the above.

3.2.2 Requirements for Decommissioning a Production Installation

Operators are required to provide evidence of financial responsibility as activity relates to the abandonment of wells and decommissioning of production installation.

> "The operator, on behalf of the participating interest holders and parties, must submit a decommissioning program for Board approval, including its proposed evidence of financial responsibility for such decommissioning, at least 6 months prior to the commencement of production. Any such decommissioning program may be revised as circumstances may require from time to time." (GRFRR, Section 5.6 (b))
>
> "In providing evidence of financial responsibility, the operator, on behalf of the participating interest holders and parties, must include the following:
>
> - the projected cost associated with the abandonment of the wells and the decommissioning of the production installation;
> - the manner and form in which the operator will ensure, on behalf of the interest owner, that the abandonment/decommissioning costs will be paid;
> - the manner, form and associated costs in which the decommissioned production installation will be maintained (in the event that entire removal is not required);
> - the manner and form in which any residual liability will be dealt with by the operator and interest owner, in the event any subsequent claims arise after such abandonment/decommissioning occurs, with respect to damages attributable to the operator's work or activity; and
> - such other information as the Board may consider necessary." (GRFRR, Section 5.6 (d))

3.2.3 Requirements for any Other Work or Activity

For work that does not inherently or exclusively relate to a development, is not drilling- or production-related, decommissioning work or activity, operators are required to furnish evidence of financial responsibility that demonstrates their ability to satisfy certain financial liabilities.

In addressing the monetary limits of the insurance, the operator must provide evidence for the following risks in the amounts indicated below:

- Comprehensive General Liability - at least $5 million (U.S.) combined single limit per occurrence
- Hull & Machinery - in an amount not less than the value of the vessel
- Protection & Indemnity - in an amount which is the greater of $5 million (U.S.) or the value of the vessel:
  - includes Removal of Wreckage and Debris
  - includes an extension to insurance in respect of Specialist Operations or ROV Operations, as appropriate, for a separate limit of not less than $5 million (US). (GRFRR, Section 5.7 (b))

3.3 Financial Responsibility Offshore Oil and Gas-National Energy Board

Companies undertaking oil and gas exploration and production activities, as well as other authorized activities in areas covered by COGOA, are liable for loss or damage that they may cause as a result of a spill and debris in accordance with the general laws of Canada. COGOA and the Inuvialuit Final Agreement in the Inuvialuit Settlement Region hold the company that has been granted an authorization pursuant to COGOA accountable as they impose absolute liability on the operator. When absolute liability is imposed, an operator cannot avoid liability on the basis that there was no fault or negligence. In the case of COGOA, this absolute liability is limited to the prescribed amounts found in the Oil and Gas Spills and Debris Liability Regulations or the Arctic Waters Pollution Prevention Regulations for the Canadian Arctic offshore.

The NEB's Financial Viability and Financial Responsibility Guidelines explain the information that an applicant seeking an authorization under the COGOA should provide to the NEB to demonstrate financial viability with respect to the applied-for activity as well as how it will meet the financial responsibility requirements pursuant to COGOA. Financial viability is defined as the extent to which an Applicant is financially capable of conducting the applied-for activity safely and in an environmentally responsible manner. The Applicant must provide an estimate of the costs of doing so and demonstrate its ability to pay for these costs. Financial responsibility is defined as the extent to which an Applicant is financially capable of implementing its worst-case scenario spill contingency plan. For the purposes of these Guidelines, the worst-case scenario is a severe event with extreme and significant effects and consequences. The Applicant must provide an estimate of all costs associated with control of the incident, cleanup of the environment, and compensation to affected parties, and demonstrate its ability to pay for these costs.

Prior to receiving an authorization for any oil or gas activity onshore or offshore, an Applicant must demonstrate that it is capable of acting in a financially responsible manner for the life of the proposed operations. The NEB has full discretion over the proof of the Financial Responsibility that the Applicant must put in place. There is no upper limit on the amount of Financial Responsibility which the NEB may require.

COGOA requires the holder of an authorization to ensure that the proof of financial responsibility remains in force for the duration of the work or activity. If there is a draw down on a portion of the funds provided to the NEB as proof of Financial Responsibility, the NEB could require an operator to replenish those funds. The NEB may suspend or revoke the authorization if the operator fails to maintain proof of Financial Responsibility.

The Applicant must file its Financial Viability and Financial Responsibility information at the same time as it files its application for an authorization. The Applicant is encouraged to contact the NEB to request a pre-application meeting to discuss the process requirements for filing the Financial Viability and Financial Responsibility information prior to filing an authorization application.

As part of its authorization application, the Applicant must provide two separate cost estimates: (1) an estimate for the cost of completing the applied-for activity in a safe and environmentally responsible manner and (2) an estimate for the total cost of implementing its spill contingency plan for its worst-case scenario. In addition, the Applicant will provide an explanation as to how these estimated costs were developed and will be covered as well as supporting documentation demonstrating the Applicant's ability to pay these costs.

As a minimum, an Applicant is expected to file an application for an onshore activity with the NEB no less than 2 months, and an application for an offshore activity no less than 6 months, prior to the time a decision is requested from the NEB. In the case of complex applications, additional time may be required. Drafts of any financial instruments to be provided, such as a letter of credit, are required prior to the filing of the final instruments. Final instruments may be filed with the NEB after the NEB's assessment of the authorization, but before it is issued.

In order to determine the level of Financial Viability and Financial Responsibility required, the NEB needs certain cost information to address both the prevention of an incident (Financial Viability) and the response to an incident, if it were to occur (Financial Responsibility). The cost estimate information required includes the following.

To address financial viability, the Applicant must provide the estimated cost of the applied-for activity, including all expenses to be incurred, to ensure that the activity can be conducted in a safe and environmentally responsible manner. In particular, the Applicant is expected to identify the cost of all activities included in its operations, including the effective implementation of its management system.

In order to address financial responsibility, the Applicant will provide the Board with its estimate of the costs of implementing its spill contingency plan for its worst-case scenario. The application must include a description of this scenario, the consultation process undertaken to determine it, and the justification for the choice of scenario. The estimated cost associated with implementing its spill contingency plan for its worst-case scenario should include the cost of:

9. Containing the incident
10. Cleaning up the environment
11. Compensating affected third parties

Containing the incident refers to stopping any flow of hydrocarbons into the environment, as well as containing any spill and debris. The Applicant should submit information detailing the costs associated with containing the incident identified in the worst-case scenario for which an authorization is being sought. The list of factors below is meant to be a starting point for relevant considerations, and would be customized for the nature, magnitude, and scale of the proposed project. It is intended to be illustrative and not exhaustive. The Applicant should consider all factors that have a bearing on the worst-case scenario costs, including:

- The type, scale, timing, and location of the proposed activity
- Stopping the flow of hydrocarbons
- Key response strategies and methods for spill and debris containment, monitoring, tracking recovery, and cleanup on surface water, the subsurface, shoreline, ice, and ice-infested waters, as applicable
- Rate of release, volume, and properties of the product that could be released in the event of a worst-case scenario
- Required support systems, including vessels and ice breakers
- All factors that can cause harm to the proposed activities and how such risk factors would be managed
- Environment, logistic, and geographic factors that affect stopping, containing, and cleaning up the released product.

The Applicant should provide the NEB with an estimated cost for environmental cleanup under the worst-case scenario as well as a rationale for how those costs were derived. The Applicant should consider all factors that have a bearing on the costs of cleaning up the environment.

The Applicant must provide the NEB with its estimated cost for compensating affected third parties in the case of its worst-case scenario as well as a rationale for how those costs were derived. The estimated costs should consider all factors which contribute to the cost of compensating third parties from an incident. The NEB expects the Applicant to engage potentially affected third parties when deriving estimates for compensation, which may involve the consideration of traditional knowledge.

The operator is expected to file an update when there is a material change to the demonstration of Financial Viability or Financial Responsibility, such as a change to the estimated cost of the applied-for activity, the assessment of risk, the spill contingency plan, or the estimated costs of a worst-case scenario. If a material change is made to any of these factors, the operator must notify the NEB in writing immediately upon the change occurring.

The Accountable Officer of the Applicant must sign off on the worst-case scenario cost estimates and verify the accuracy of the information filed with the NEB in accordance with the Guidelines. The Accountable Officer will be the person responsible for financial and human resources as well as technical and operational activities within the Applicant's corporation. In most cases, this will be the Chief Executive Officer. The Operator should notify the NEB if the Accountable Officer within a corporation has changed.

As part of its application, an Applicant must demonstrate Financial Viability with respect to the applied-for activity and how it will meet the Financial Responsibility requirements to address a worst-case scenario.

Demonstration of an Applicant's ability to pay for the costs of safely conducting the applied-for activity can be achieved by explaining how the costs for the activity will be paid for over the life of the activity. This explanation is expected to be supported by the submission of the Applicant's audited financial statements and the Applicant's most recent credit rating reports, which need to be investment grade (B-rating) or above. The audited financial statements and credit rating reports of an Applicant's parent corporation will not be considered sufficient. The NEB may consider other evidence of Financial Viability, in addition to those forms described above, that indicate sufficient financial strength and liquidity.

To demonstrate coverage for financial responsibility, an Applicant must demonstrate its ability to pay the full cost of addressing a worst-case scenario.

The NEB will require unfettered access to a portion of the funds provided as proof of Financial Responsibility in the form of an irrevocable letter of credit. The NEB requires the amount of the unfettered portion to be equal to or greater than the estimated cost of stopping and containing an incident. This does not mean that the NEB is obligated to use these funds exclusively for the costs associated with stopping and containing the event; rather, the NEB may choose to use the funds for any costs associated with the incident, including compensation to affected persons.

The following include the types of financial instruments that the NEB will accept:

i) Unfettered funds: A financial security with unfettered access ensures that the Board will have immediate access to funds, if necessary, to address costs resulting from an incident where the operator does not pay for these costs itself. Unfettered funds will likely be in the form of an irrevocable letter of credit from a Canadian chartered bank, with a Calgary office, indicating the beneficiary as "Her Majesty

The Queen in Right of Canada as represented by the National Energy Board". The letter of credit must be effective for at least the duration of the authorized activity as well as any additional period as directed by the NEB. The letter of credit can be drawn upon on demand by the NEB if an incident were to occur. Any letter of credit provided must be unconditional and irrevocable, and solely dedicated to providing funds to remedy damages and losses from an incident.

In addition to the unfettered funds, the NEB requires the Applicant to carry insurance coverage.

ii) Insurance: The NEB requires the operator to hold, at a minimum, spill and pollution insurance. The Applicant must provide a Certificate of Insurance as well as a letter to the NEB signed by the Applicant's Accountable Officer indicating:

- The name of the insurance carrier
- The amount of the coverage
- The estimated time required before payout occurs
- That the Applicant has sufficient funds to pay the deductible amount
- The length of time for which the insurance coverage has been put in place
- That the Board will be notified at least 60 days in advance if insurance will be cancelled or changed
- The listing of all exclusions
- That the insurance provider has a credit rating of investment grade (B-rating) or above
- that each policy names the Board as an insured party

If an Applicant is covered by more than one insurance policy, then in addition to the above requirements, a review of all the combined insurance policies must be provided by an independent third party.

If an Applicant proposes to self-insure instead of using third-party insurance, the Accountable Officer is required to confirm that sufficient funds are and will be available to address the costs of addressing a worst-case scenario.

If the costs of the worst-case scenario are not fully covered through the unfettered funds and insurance, the operator must provide the remainder of the costs.

iii) Other financial instruments: The remainder of the estimated worst-case scenario costs not covered by the irrevocable letter of credit or insurance may be addressed through one or more of the following:

- Additional third-party insurance: The Applicant will provide the NEB the specific information outlined in section 7(ii).
- Audited financial statements: demonstrating the Applicant has sufficient financial strength with adequate cash and/or easily accessible capital to cover the costs of a worst-case scenario. The audited financial statements of the Applicant's parent corporation will not be considered acceptable (unless the parent corporation has signed a parental guarantee).
- Letter of credit: an irrevocable letter of credit may be provided in addition to the one which comprises the unfettered portion of the Financial Responsibility as set out in section 7(i). The letter of credit must be from a Canadian chartered bank, with a Calgary office, and indicate the beneficiary as "Her Majesty The Queen in Right of Canada as represented by the National Energy Board." The letter of credit must be effective for the duration of the authorized activity as well as any additional period as directed by the NEB.
- Parental or third-party guarantee: The corporate affiliate or parent company can provide the NEB with a letter indicating that, in the event of an incident, the NEB would be the recipient of sufficient funds from the corporate affiliate or parent company to cover the costs of the worst-case scenario. This letter must be accompanied by audited financial statements and the most recent credit rating reports from the parent company or corporate affiliate.
- Industry group fund: The Applicant may provide evidence of participation in an industry group fund that may be used to cover the cost of a worst-case scenario.
- Any other arrangement acceptable to the NEB.

Currently, the NEB does not consider surety bonds an acceptable form for demonstrating Financial Responsibility.

3.4 Financial Guarantees for Uranium Mines-Canadian Nuclear Safety Commission

The Nuclear Safety and Control Act and its regulations require that applicants and licensees make adequate provisions for the safe operation and decommissioning of existing or proposed operations. Safe operation and decommissioning include the development of acceptable decommissioning plans, the provision of credible estimates of the costs of implementing such decommissioning plans, the provision of corresponding measures to ensure that the costs of decommissioning will be met, and (ultimately) the implementation and completion of accepted decommissioning plans. The Nuclear Safety and Control Act and its regulations do not prescribe specific decommissioning methods or the types of funding to be established. Applicants and licensees required to submit decommissioning plans maintain the flexibility to propose those decommissioning plans and financial guarantees that they consider appropriate to their individual situations. Financial guarantees are required and must be sufficient to cover the cost of decommissioning work resulting from licensed activities that have taken place prior to the license period, or will take place under the current license.

Estimates of the costs of implementing proposed decommissioning plans should address all decommissioning activities required during operations and after shutdown, including management or disposal of all wastes (including spent nuclear fuel), monitoring, and ongoing maintenance of any institutional controls. The CNSC will not permit credit for the salvage of equipment or materials in costing the implementation of proposed decommissioning plans. Consequently, such equipment or materials should be considered as waste. Estimates should include unit costs for each phase of the decommissioning plan, and should be prepared in accordance with generally accepted accounting and quantity-surveying methods and procedures. These estimates should accurately reflect local construction rates for labour and materials, should be sufficiently detailed to demonstrate accuracy and facilitate independent verification, and should assume that the work will be completed by competent independent contractors. There are criteria for determining whether an estimate of the decommissioning costs can be categorized as Grade A, B, or C. "Grade A" estimates are the most accurate and therefore require the smallest associated "contingency allowance" (10 percent). "Grade C" estimates are considered to be the least accurate and consequently require a contingency allowance of 25 to 30 percent. "Grade B" estimates are of intermediate accuracy requiring a contingency allowance of 15 to 20 percent. The applicant should indicate the grade of the estimate and include the appropriate contingency allowance in the total cost estimate. If the impacts of proposed operations, or the effectiveness of specific decommissioning options, are difficult or impossible to estimate with precision, or to substantiate with confidence, it may be cost-effective or necessary to offset these deficiencies by estimating or funding credible worst-case scenarios.

3.4.1 Financial Guarantees

The CNSC must be assured that it or its agents can, upon demand, access or direct adequate funds if a licensee is not available to fulfil its obligations for decommissioning. Measures to fund decommissioning may involve various types of financial security. The acceptability of any of these measures will be determined by the CNSC on the basis of the general criteria of liquidity, certainty of value, adequacy of value, and continuity.

The following are examples of acceptable financial guarantees: cash, irrevocable letters of credit, surety bonds, insurance, and expressed commitments from a government (either federal or provincial). Parent company guarantees and pledges of assets do not satisfy the acceptance criteria listed above and are not acceptable as a financial guarantee.

3.5 Pipelines-National Energy Board Act

In May 2014, the NEB announced its decision on NEB-regulated pipeline companies' set-aside and collection mechanism applications (MH-001-2013). The purpose of these mechanisms is to provide money to pay for pipeline abandonment.

By January 1, 2015, NEB-regulated pipeline companies must have a set-aside mechanism in place to begin accumulating funds to pay for pipeline abandonment. Most pipeline companies must establish a trust or provide a letter of credit issued by a Schedule 1 bank or a surety bond supplied by a surety company regulated under the Trust and Loan Companies Act. The NEB will require almost all pipeline companies to provide their trust agreement, surety bond, or letter of credit for approval.

The NEB will regularly review companies' estimates of abandonment costs, the coverage provided by their set-aside mechanisms, and the assumptions about how those funds will grow. To allow for greater transparency and to facilitate consultation, the NEB expects pipeline companies to consider specific tools to communicate information about abandonment funding. Additionally, the amount of abandonment funds being set aside must be included in annual reports filed with the NEB.

In 2009, as a part of the RH-2-2008 Reasons for Decision, the NEB directed all pipeline companies to begin setting aside abandonment funds. That decision set out guiding principles and considerations, and a list of attributes for any mechanism that would be used to set aside funds for pipeline abandonment. It also established a 5-year Action Plan for companies to follow.

The NEB's decision on set-aside and collection mechanisms for pipeline abandonment cost funding is the tenth and final step of the Action Plan.

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CANADIAN PROVINCIAL REPORT—ALBERTA

1. Background and History

1.1 Mining and Minerals

As of January 1, 2014, there are 315 active leases and 912 exploration permits for metallic and industrial minerals in the Province of Alberta. There are 59 active ammonite shell agreements for quarrying or mining as well. In 2013, $7.4 million dollars Canadian (CDN) in mineral assessment expenditures was filed under the Metallic and Industrial Minerals Permit program. Several non-energy mineral resources are mined in the province. These include iron, magnetite, and gold; as well as several industrial minerals including limestone, salt, sand, and gravel. Other minerals produced or potentially available in Alberta include diamonds, ammonite, and other precious stones. There are no underground mines currently active in Alberta. The Province does, however, host four major quarries with hundreds of smaller sand and gravel pits of varying sizes in operation as well. Some sand and gravel is washed for placer minerals, such as gold and platinum, before being used for construction, fill, and cement manufacturing.

1.2 Hydrocarbon Resources

The Province of Alberta is rich in hydrocarbon resources including both conventional and unconventional sources of natural gas, crude oil, and coal. The natural gas produced in Alberta accounts for around 69 percent of the natural gas produced in Canada (Alberta Ministry of Energy 2014). There are several sources of natural gas in Alberta including conventional gas, gas from coalbed methane, and shale gas. According to the Ministry of Energy, there is an estimated reserve of 31.9 trillion cubic feet of recoverable, conventional natural gas that remains in the ground. Alberta’s coal seams could contain as much as an additional 500 trillion cubic feet of coalbed methane. Coal reserves have a current estimate of 29.9 billion tonnes remaining to be mined (Alberta Ministry of Energy 2014). Alberta’s total coal production in 2011 was 36.9 million tonnes of marketable coal (Alberta Ministry of Energy 2014).

Production of conventional oil resources in Alberta began in 1914, when the province's first major oil field was discovered at Turner Valley. The successful drilling of a well at Leduc in 1947, just south of Edmonton, transformed the province overnight from oil-poor to oil-rich. As a result of this boom, many thousands of abandoned orphan wells exist in the province. As of June 2013, there are approximately 15,000 abandoned wells, representing 35 percent of all wells in the province. Alberta hosts the third largest proven crude oil sand reserve in the world (Alberta Ministry of Energy 2014). Oil sands production has expanded rapidly over the last decade and is expected to increase from 1.9 million barrels per day in 2012 to 3.8 million barrels per day in 2022 (Alberta Ministry of Energy 2014).

2. Regulatory Structure

2.1 Agency Structure

Mining and petroleum resources are regulated by the Ministry of Energy and the Ministry of Environment and Water. Non-energy minerals are regulated by the Alberta Environment and Sustainable Resource Development (AESD), which is a part of the Ministry of Environment and Water. The Lands and Forest Section of AESD is responsible for administering applications for the exploration and extraction of sand, gravel, clay, marl (mixture of clay and lime), topsoil, and peat.

The Alberta Energy Regulator (AER), which is a part of the Ministry of Energy, is responsible for regulating the life cycle of oil, oil sands, natural gas, and coal projects in Alberta. The AER regulates conventional and unconventional oil and gas resources activities from application and construction to production, abandonment, and reclamation. The AER was created in December 2012 as the single regulator for upstream oil, gas, oil sands, and coal projects in the province. On March 31, 2014, AER officially assumed AESD's responsibilities with respect to regulating oil sands and coal.

2.2 Statutory and Regulatory Framework

The Environmental Protection and Enhancement Act (EPEA), Coal Conservation Act (CCA), Mines and Minerals Act (MMA), Oil and Gas Conservation Act (OGCA) and Oil Sands Conservation Act (OSCA) are the primary statutes from which the regulations responsible for Dismantlement, Reclamation, and Remediation (DR&R) activities for mining and petroleum activities are promulgated. The CCA, OSCA, MMA and the EPEA all impose financial security requirements as conditions for the issuance of licenses, permits, approvals, registrations, variances, or reclamation certificates under these various laws.

The MMA (Chapter M-17) governs the management and disposition of rights in Crown-owned mines and minerals, including the levying and collecting of bonuses, rental, and royalties. There are several regulations promulgated under the MMA, which include a requirement to provide a security deposit before conducting work. For example, a security deposit is required to address damage to lands under Exploration Regulation 284/2006 (Forest Act, Mines and Minerals Act, Public Highways Development Act, Public Lands Act).

The Oil and Gas Conservation Rules Regulation 151/1971 under the OGCA, Section 1.100 identifies the security deposit requirements for wells and facilities, excluding oilfield waste facilities. The regulation indicates that the regulator may require a security deposit prior to issuing a license or approval if a licensee fails a licensee liability rating assessment, or at any time it deems appropriate in order to carry out DR&R activities for the well or facility. The licensee or approval holder has the option to post the full amount of security.

The Conservation and Reclamation Regulation 115/1993 (CRR), under the EPEA, sets out the requirements for the amount, form, adjustment, return, retention, and forfeiture of the security posted by an operator. The CRR provides details regarding closure plan requirements as well.

In addition to statutes and regulations, several directives have been published by the regulatory agencies to provide further instruction regarding how mining and petroleum securities are to be determined, evaluated, and managed. These directives are discussed in Section 3.

3. Security/Financial Assurance

3.1 Coal and Oil Sands Mining Sector

Financial assurance and security requirements for coal and oil sands are regulated separately from other mineral resources. Mining liabilities are administered through the Mine Financial Security Program (MFSP). The MFSP collects financial security from the oil sands and coal industry in an effort to protect the public from paying for end-of-life project closure costs. Effective March 29, 2014, the AER has assumed responsibility for this program, originally established by AESD in 2010. Operators are responsible for carrying out suspension, abandonment, remediation, and surface reclamation work to the standards established by the province and to maintain care-and-custody of the land until a reclamation certificate has been issued. The approval holder must have the financial resources to complete these obligations. The MFSP takes an asset-to-liability approach to managing financial risks.

3.1.1 Types of Security/Financial Assurance Deposits

The MSFP includes four types of financial security deposits (Table 3.1-1), focusing on various potential risks in the life cycle of a mine:

Table 3.1-1 Four Types of Financial Assurance Deposits Associated with Coal and Oil Sands

<table>
<tr><th>Type of Security Deposit</th><th colspan="3">Description of Security Deposit</th></tr>
<tr><td rowspan="4">Base Security Deposit</td><td rowspan="4">Required for all existing and new projects. Used for suspension care-and-custody activities to maintain the security and safety of site until another party assumes responsibility for the project or all infrastructure is removed and the site is reclaimed.</td><td>New mine-mouth coal mine</td><td>$2,000,000 CDN</td></tr>
<tr><td>New export coal mine</td><td>$7,000,000 CDN</td></tr>
<tr><td>New Oil sands mine with no EPEA approval as of 1/1/2011</td><td>$30,000,000 CDN</td></tr>
<tr><td>New oil sands mine and upgrader with no EPEA approval as of 1/1/2011</td><td>$60,000,000 CDN</td></tr>
<tr><td>Operating Life Deposit</td><td colspan="3">Addresses project risks that coincide with a mine's end-of-life. Posted when there are fewer than 15 years of reserves remaining in order for all outstanding abandonment, remediation, and surface reclamation costs to be fully secured by the time there are fewer than 6 years of reserves remaining.</td></tr>
<tr><td>Asset Safety Factor Deposit</td><td colspan="3">Ensures that all MFSP liabilities are fully funded in the event that a company's assets fall below an acceptable level (MFSP-asset-to-liability ratio falls below 3.0). Must deposit amount of security to raise ratio back up to 3.0.</td></tr>
</table>

Table 3.1-1 Four Types of Financial Assurance Deposits Associated with Coal and Oil Sands

Type of Security Deposit	Description of Security Deposit
Outstanding Reclamation Deposit	Addresses the risks posed by a company that defers its reclamation obligations. A company is required to post this type of security deposit when it fails to meet its reclamation plan targets.

If a company elects to post the full security, the above security deposits no longer apply. As part of the amendments implementing the MFSP, qualifying environmental trusts were added to the forms of security that are acceptable under the CRR. The most popular forms of security used are cash and letters of credit. The Government of Alberta holds the security. Cash securities are put into the Consolidated Cash Investment Trust fund and managed by Alberta Finance.

3.1.2 Calculation of Security/Financial Assurance

For most oil sand operations subject to the MFSP, securities are calculated annually based on the maximum disturbance expected during the upcoming year; however, there are two operations that were grandfathered secured at 3 cents per barrel bitumen production. The security paid by these two grandfathered oil sand mines is insufficient for covering the full cost of reclamation (AER 2014b). For coal mine operations, annual securities are based on the maximum disturbance from the previous year rather than the upcoming year.

The Guide to the Mine Security Financial Security Program indicates that the financial security will usually equal the sum of the four deposits described in Table 3.1-1; however, if this sum exceeds the MSFP Liability, the security will be adjusted down to equal the liability. The required security can increase when there is a higher liability, lower assets, or less reclamation is accomplished than was planned. Conversely, the amount of security can decrease with a lower liability, higher assets, or more reclamation occurs than planned. .

3.2 Conventional Petroleum Resources Sector

Financial assurance and DR&R requirements for conventional oil and gas resource activities are administered by AER. The AER liability management programs are designed to protect against significant potential environmental issues and costs associated with industry DR&R activities including the eventual abandonment of sites previously involved in petroleum resource recovery.

Upon completion of oil and gas activity in an operating area, the responsible company must return the land as close as possible to its original state. This process is known as reclamation and is considered complete only when the habitat around the abandoned well returns to its original form and the abandoned well cannot be seen from the surface.

3.2.1 Security/Financial Assurance Requirements

The requirements for environmental protection and safety concerning abandonment of wells, pipelines, and associated facilities are described in AER Directive 020: Well Abandonment. For oil and gas wells, a company retains a 25-year liability for surface reclamation issues and lifetime contamination liability. When a well or oil and gas facility is no longer productive, the owner of the well or facility must reclaim the land and apply for an AER reclamation certificate. Reclamation of the site must address both surface reclamation issues and subsurface contamination. The AER issues the reclamation certificate once the site is reclaimed and remediated to the standards set by AER. By contrast, an uncertified, un-reclaimed well liability is based solely on its reclamation cost.

Security funds are collected from operators who hold an EPEA approval pursuant to the Activities Designation Regulation unless exempted in the CRR. Financial assurance must be provided before a new or initial approval is issued by AER. When an approval is amended or there is a change in the amount of security required, the security must be provided within 30 days of a request by the director. All or part of the security is returned to the operator once a reclamation certificate is issued. If the operator fails to meet its reclamation obligations, the security may be forfeited to cover costs for AER to reclaim the costs. AER can collect additional money from the operator for situations in which insufficient funds were provided to address reclamation of a well or oil and gas site.

3.2.2 Form of Financial Assurance/Security

Security can be submitted in cash, bonds, or letters of credit. Interest on security submitted as cash is paid to the operator.

3.2.3 Calculation of Financial Assurance

The AER has several liability management rating programs for addressing DR&R liability costs. Most upstream wells or facilities fall under the Licensee Liability Rating (LLR) Program; however, some well sites or facilities fall under the Large Facility Liability Management Program (LFP). Oilfield waste facilities fall under the Oilfield Waste Liability (OWL) Management Program. Each licensee or approval holder is required to conduct a liability assessment to estimate the cost to suspend, abandon, or reclaim a site based on the liability management rating program under which it falls. The methodology and procedure for conducting a liability assessment for each liability management rating program are found in a series of directives written by the AER Energy Resources Conservation Board (ERCB). These directives are listed in Table 3.2-1.

Table 3.2-1 Liability Management Rating Programs and Associated Directives

Liability Management Rating Program	Relevant Directives
Licensee Liability Rating	Directive 006: License Liability Rating (LLR) Program and License Transfer Process (Directive 006) Directive 011: Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs (Directive 11)
Large Facility Liability Management Program	Directive 024: Large Facility LMP (Directive 024)
Oilfield Waste Liability	Directive 075: OWL Program (Directive 075)

3.2.3.1 Licensee Liability Rating Program

For most upstream oil and gas wells and facilities that fall under the LLR program, a general cost estimate is adequate for determining liability costs and the amount of security required. Like the liability management rating, the LLR is the ratio between a licensee or approval holder's deemed assets and its deemed liabilities. When determining a site's LLR, the deemed assets are adjusted based on previously provided security deposits. The licensee or approval holder must calculate its LLR annually to determine if the level of financial assurance for a well or facility is sufficient. In simple terms, if the deemed liabilities are greater than the adjusted deemed assets, resulting in an LLR less than 1.0, the licensee or approval holder must post additional security funds.

The calculation of a site's deemed assets is based on a well or facility's adjusted oil equivalent production from the previous 12 calendar months multiplied by a 3-year average netback. For producers, an industry netback is used, whereas for non-producers, a site-specific netback must be calculated and used to determine the annual deemed asset estimate. Netback is earnings before interest, taxes, and depreciation and is equal to gross margin (midstream revenue less cost of goods sold) less direct operating costs and applicable general and administrative expenses.

The process for calculating the deemed liability for an individual well or well facility is based on the sum of two liability costs (Appendix 6, Directive 6). These two liability costs are:

- Abandonment liability
- Reclamation liability.

Each of these liability inputs is calculated separately before being summed together to establish a well or facility's total deemed liability(Table 3.2-2). The initial deemed liability amount is then posted by licensee or approval holder as a security for the well or facility.

Table 3.2-2 Status Designation for Wells and Facilities Used to Calculate Liabilities

Status Class	Status Class Description
Active	Well or facility has reported operations to AER within last 12 months
Inactive	Well or facility has not reported operations to AER within last 12 months
Abandoned or un-reclaimed	Well or facility has been abandoned, but has not received reclamation certificate
Problem site designation	Well or facility with potential or which has been assessed to have an abandonment or reclamation liability greater or equal to 4 times the normal calculated liability typical for site in region.
Gas plant	Facility licenses through Directive 056 as a gas processor or gas fractioning plant that are not included in large facility LMP

For multi-well pads, the deemed liability is the sum of the abandonment liability cost for each well plus the reclamation liability cost for each well. In order to determine a well or well facility's abandonment liability cost, an operator must determine within which abandonment reclamation region the well is located by consulting the Regional Abandonment Cost Map (Directive 006, Appendix 8). Section 6 of Directive 011 provides regional well abandonment costs. These costs are based on geographic area, depth, and downhole completion scenarios (Table 3.2-3). Abandonment costs vary by region, increasing with depth and the level of downhole completion. Table 3.2-4 provides the range of costs for each abandonment area from the lowest cost to the highest cost based on well depth and downhole completion. The full set of tables is provided in Directive 011. Additional costs can be applied to the abandonment liability costs for groundwater protection, vent flow repair, gas migration, and multiple-event sequence factor. A monetary value of $ 17,000 CDN per well equivalent is provided to account for facility abandonment costs.

Table 3.2-3 Abandonment Liability Cost Parameters

Area	Depth Class	Downhole Completion Class
Area 1 – Medicine Hat	0 to 1,199 metres (A)	Empty, no perforated (EN)
Area 2 – Calgary/Edmonton	1,200 to 1,999 metres (B)	Empty, perforated (EP)
Area 3 – Drayton/Grand Prairie	2,000 to 2,499 metres (C)	Tubing only (TO)
Area 4 – Lloydminster	2,500 to 2,999 metres (D)	Tubing and rods (TR)
Area 5 – Athabasca/Peace River	3,000+ metres (E)	
Area 6 – High Level		

Table 3.2-4 Range of Well and Facility Abandonment Costs in Canadian Dollars

Downhole Completion Class/Depth Class Combination	Area					
	Medicine Hat	Calgary/ Edmonton	Drayton/ Grand Prairie	Lloydminster	Athabasca/ Peace River	High Level
EN/A	$ 10,933	$11,267	$ 11,667	$ 10,933	$ 11,400	$ 15,200
TR/E	$ 93,391	$ 96,864	$ 100,715	$ 93,391	$ 97,748	$ 109,418

Reclamation liability costs, based on a Regional Reclamation Cost Map (Appendix 9 of Directive 06), are calculated at 100 percent of the total reclamation liability for the first well and 10 percent for each subsequent well. Section 8 of Directive 011 provides a single cost for each of the seven reclamation cost regions described in Directive 006, Appendix 9.

- Grasslands Area East: $16,500 CDN
- Grasslands Area West: $25,250 CDN
- Parklands Area: $27,250 CDN
- Foothills Area: $29,250 CDN
- Alpine Area: $42,125 CDN
- Western Boreal Area: $34,000 CDN
- Boreal Area: $23,875 CDN

3.2.3.2 Large Facility Liability Management Program

The LFP applies to historical, current, and future licensed (new or amended sulphur recovery gas plants, standalone straddle plants, and in-situ oil sands central processing facilities having an ERCN-approved design capacity of 5,000 cubic metres per day [AER 2009a, Directive 24]). Large facilities must follow the methods described in the LLR program to determine basic security requirements, but are also subject to additional requirements documented in AER Directive 24, which describes the requirements unique to large facilities. One component that is unique to the LFP is facility-dedicated security deposits. Currently, facility-dedicated security deposits are voluntary. A licensee of a facility in the LFP may at any time voluntarily provide the ERCB with a facility-dedicated security deposit in any amount. However, an operator or its working interest partners can initiate a request in writing that ERCB require that the deposit become mandatory. Additional details regarding the LFP are provided in Directive 24.

3.2.3.3 Oilfield Waste Liability Program

The OWL program applies to all ERCB-approved waste management facilities except if the approval was issued for a facility solely dedicated to landfill purposes (AER 2009b, Directive 75). The OWL Program requires an non-producer licensee or eligible producer licensee, regardless of its liability management rating, to provide the ERCB with a facility-specific security deposit for the amount by which a waste management facility's deemed liabilities exceed its deemed assets. Facilities that do not have a total of 12 calendar months of waste throughput must provide a security deposit equal to the full deemed liability of the facility. Additional details regarding OWL facility security requirements are presented in Directive 75.

3.3 Non-Energy Mineral Resources Mining Sector

Financial assurance and securities for non-energy mineral resources are administered by the AESD.

3.3.1 Forms of Security/Financial Assurance

Alberta accepts the following forms of financial assurance (Conservation and Reclamation Regulation AR 115/93, 21):

- Cash
- Cheques and other similar negotiable instruments payable to the President of Treasury Board and Minister of Finance
- Government guaranteed bonds, debentures, term deposits, certificates of deposits, or investment certificates assigned to the President of Treasury Board and Minister of Finance
- Irrevocable letters of credit or irrevocable letters of guarantee, performance bonds, or surety bonds in a form acceptable to the Director
- Qualifying environmental trusts within the meaning of subsection 248(1) of the Income Tax Act (Canada)
- Any other form that is acceptable to the Director.

3.3.2 Calculation of Security

The amount of security must cover the cost of reclamation in the event that the operator is unable to complete reclamation on the site.

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CANADIAN PROVINCIAL REPORT—BRITISH COLUMBIA

1. Background and History

1.1 Mining Sector

British Columbia's mineral exploration and mining industry is an integral part of the provincial economy. The province has been mined since the mid-1800s. British Columbia produces and exports a significant amount of copper, gold, silver, lead, zinc, molybdenum, coal and industrial minerals. The Hudson's Bay Company first started producing coal on Vancouver Island in the 1840s, and the discovery of gold along the Fraser River in the 1850s sparked a major gold rush. Until the early 1960s, most mining activities were accomplished underground; however, with open-pit mining becoming more feasible, it became increasingly popular. Several large copper mines opened, including Highland Valley Copper, which is the largest open-pit operation in North America.

1.2 Petroleum Sector

British Columbia is Canada's second largest producer of natural gas. There are approximately 400 trillion cubic feet of natural gas in different locations throughout the province. Petroleum industry activities are vital to the provincial economy, generating significant economic wealth each year and employing thousands of British Columbians. A total of 1,416 wells have been drilled in British Columbia since 2006. Total Crown revenue collected from oil and gas royalties, sales of gas rights, fees, and rentals was $2.14 billion dollars Canadian (CDN). Production of natural gas was 1.16 trillion cubic feet. The sales value of oil and gas production was $7 billion CDN. Industry investment was $6.1 billion CDN. Gas is produced at 47 plants in northeastern British Columbia, and there are 32,400 kilometres of gas-gathering and transmission lines to bring the gas to market. There are a number of proposals for pipelines and terminals to export natural gas overseas from the coast of British Columbia. Currently, there is a federal ban on all offshore drilling for British Columbia.

2. Regulatory Structure

2.1 Regulatory Agencies

There are three agencies across two Ministries that work together to enforce the statutory requirements for reclamation securities in British Columbia:

- The Environmental Protection Division (EPD; Within the Ministry of Environment)
- The Mines and Minerals Division (MMD; Within The Ministry of Energy and Mines)
- The Oil and Gas Commission (OGC; Within the Ministry of Energy and Mines)

The EPD regulates land remediation efforts for abandoned mines, wells, and contaminated sites. These sites have been found to have no owner or the owner is unable to remediate the site. In these cases, the EPD remediates the site and will seek compensation for the costs of its work. The roles played by the MMD and the OGC with respect to dismantlement, reclamation, and remediation (DR&R) activities are described below.

2.1.1 Mining Sector

The MMD is responsible for the regulation of mining in British Columbia. It implements policies and programs that encourage the responsible development of these resources and ensures that all mining activities respect the safety of workers, the public, and the environment. The MMD manages British Columbia's substantial mineral resources.

2.1.2 Petroleum Sector

The OGC, a Crown corporation, was originally created through the Oil and Gas Commission Act to be an independent, single-window regulatory agency with responsibility for overseeing oil and gas operations in British Columbia. Since October 2010, the OGC derives its authority from the Oil and Gas Activities Act (OGAA).

The OGC is responsible for regulating oil and gas activities from exploration and development through production, pipeline transportation, and ultimately decommissioning and reclamation. The OGC is helping the oil and gas industry grow and prosper by streamlining the applications and approval processes while maintaining provincial environmental standards.

2.1.3 Contaminated Sites

The Ministry of Environment EPD Land Remediation Section is responsible for the investigation and remediation of contaminated sites in British Columbia. The Land Remediation Section focuses on remediation of brownfields, orphan sites, complex, high-risk contaminated sites, and mid- to low-risk contaminated sites. In order to remediate these sites, the Land Remediation Section is authorized through the Ministry of the Environment to request a security deposit. Sites undergoing DR&R activities under the authority of the Mines Act or OGAA for which a security deposit has already been collected are exempt from security requirements by the Land Remediation Section.

2.2 Statutes and Regulations

2.2.1 Mining Sector

The Mines Act and accompanying Health, Safety, and Reclamation Code for Mines in British Columbia provide the legislative framework for the management of mines in the province. The MMD (through the Chief

Inspector of Mines) issues mining permits, and securities must be posted before a mine permit is issued. The security must be in an amount and type that the Chief Inspector of the Mines finds acceptable.

Financial security will be required to ensure that there are sufficient funds to cover all outstanding reclamation obligations for a mine before a permit is issued. Under the Environmental Management Act, all mines are required to be returned to their original state after mining operations have ended. The Environmental Management Act allows for the collection of a security deposit for contaminated mine sites; however, mine sites for which a security deposit has already been collected under the Mines Act are exempt from this requirement. A security deposit under the Environmental Management Act can be collected by the Ministry of Environment for reclamation and remediation of historical mine sites.

2.2.2 Petroleum Sector

The OGAA is the primary statute from which oil and gas regulations are promulgated. The Fee, Levy, and Security Regulation promulgated under the OGAA identify the security requirements for oil and gas pipeline activities in British Columbia. The OGC provides guidance documents, such as the Liability Management Rating (LMR) Program Manual, to provide permit holders with an understanding of how security deposits are calculated.

2.2.3 Contaminated Sites

The Environmental Management Act and the Contaminated Sites Regulations (375/96) allow for the reclamation and remediation of contaminated sites. The Environmental Management Act allows the Land Remediation Section to collect a security deposit to fund those reclamation and remediation activities.

3. Security/Financial Assurance

3.1 Mining Sector

The Ministry of Energy and Mines seeks to provide reasonable assurance that the province will not have to contribute to the costs of reclamation if a mining company defaults on its reclamation obligations. As a condition of Mines Act permits, the permittee must post financial security in an amount and form acceptable to the Chief Inspector of Mines. This security is held by the government until the Chief Inspector of Mines is satisfied that all reclamation requirements for the operation have been fulfilled.

Every mine site has unique management requirements and operational constraints; thus, financial security is assessed on a site-specific basis. The security is set at a level that reflects all outstanding reclamation and closure obligations. For example, mines that require long-term drainage treatment for metal leaching and/or acid rock drainage require full security to cover outstanding liability and ongoing management.

Certain mining categories are exempt from having to provide security. Categories such as exploration, advanced exploration, and mines that were producing before the Mines Act went into effect in 1969.

Mines must create Mine Closure Plans before permits are issued. The document is used to determine the amount of securities to be deposited with the Chief Inspector of the Mines. This plan is updated annually or when significant changes have occurred.

A mining permit can be issued with a Mine Closure Plan that does not return the land to its original state. The site can be modified to take advantage of existing infrastructure and can contribute to the local economy. Such sites could be turned into recreational, residential, or industry use.

3.1.1 Sand, Gravel, and Quarry Securities

The Ministry of Energy and Mines manage the issuance of permits for sand, gravel, and quarries in British Columbia. As with other forms of mining, each site is assessed a security amount specific to that site. Security is required under the Mines Act before a permit can be issued.

3.1.2 Forms of Financial Assurance Accepted for Mining Sector

The Chief Inspector of Mines accepts the following forms of reclamation security: cash, certified cheques, bank drafts, term deposits (i.e., Guaranteed Investment Certificates), Government of Canada bonds, and Irrevocable Standby Letters of Credit (ISLOCs). Term deposits and bonds may be held in a Safekeeping Agreement where the interest accrues on the deposit. In some cases, funds may be deposited to the Mine Reclamation Fund (pursuant to Section 12 of the Mines Act) or within a Qualified Environmental Trust. These funds allow interest to accrue to the credit of the account. For ISLOCs, the client’s financial institution confirms that sufficient funds exist and will be kept available by the financial institution to meet Ministry of Energy and Mines' requirements.

3.2 Petroleum Sector

The OGC has developed an LMR program to ensure that oil and gas activity permit holders carry the financial risks and regulatory responsibility of their operations through to closure. The OGC uses the LMR program to determine the amount of security deposits required under Section 30 of the OGAA.

3.2.1 Forms of Financial Assurance/Security in Petroleum Sector

The OGC accepts the following instruments as forms of security for oil and gas activities (OGC 2014b):

- Certified company cheques
- Irrevocable letters of credit

- Electronic/wire transfer from recognized Canadian financial institution.

The OGC does not accept letters of guarantees, safekeeping agreements, performance bonds, or personal cheques.

3.2.2 Calculation of Financial Assurance/Security

OGC uses its LMR program to determine the amount of security required for a permit holder to post. The LMR is the calculated ratio of deemed assets to deemed liabilities. The permit holder is required to take action to mitigate any financial risks, if deemed liabilities are greater than deemed assets, resulting in an LMR lower than 1.0. This risk can be mitigated by depositing additional security funds for operation. The LMR is calculated using the following generalized formula:

$$LMR = \frac{Deemed\ Assets + Security\ Deposit}{Deemed\ Liabilities}$$

Permit holders with a calculated LMR lower than 1.0 will be deemed high-risk and required to post a security deposit, while permit holders with a calculated LMR higher than or equal to 1.0 will not be reviewed for a security deposit. The OGC conducts LMR assessments monthly for each permit holder and evaluates security requirements bi-monthly. Procedures for calculating deemed assets and deemed liabilities are provided in British Columbia OGC LMR Program Manual. A list of permit holders and their respective LMRs is updated monthly and posted on the OGC website. If compliance with these security deposit requirements is not maintained, the OGC may cancel a permit holder’s permits or order it to cease operations. On September 4, 2014, the OGC published an industry bulletin (2014-12) in which it announced that it would be implementing updates to the calculation parameters used to determine production assets associated with its LMR program, which have remain unchanged since the implementation of the LMR program in October 2010. Industry data from the Canadian Association of Petroleum Producers Statistical Handbook for 2008 through 2012 was used to update the calculation parameters and evaluate the impact to current producers operating in British Columbia. The updated calculation parameters are planned to become effective in November 2014. Annual updates to asset parameters will be automatically implemented as new data become available. As a result of the updated parameters, the number of producers with an LMR lower than 1.0 will increase by 4, bringing the total to 21. The average LMR will decrease from 6.21 to 4.25, and the median LMR will go from 2.13 to 1.69 as a result of using the updated calculation parameters. The unsecured liability is estimated to increase from $7,638,660 CDN to $11,835,438 CDN.

3.2.2.1 New Permit Holders and Wells

Permit holders who are applying for their first well or facility permit or permit transfer may be required to achieve a security-adjusted LMR of 1.0 by posting an initial security deposit. A security deposit is calculated based on post-application inventory. If a security deposit is based on the permit holder’s first well application, the amount is determined by the factors outlined in the application.

3.2.2.2 Existing Permit Holders

If an existing permit holder's LMR drops below 1.0 at the time of a bi-annual assessment, an additional security deposit in an amount that will return the LMR to 1.0 will be required. The permit holder has to post the additional security deposit within 30 days from the date the OGC provides the request. The security deposit must be made as a single payment. A select group of existing permit holders operating prior to the implementation of the LMR program were granted the ability to provide phased payments under these circumstances. These grandfathered permit holders are not be required to submit an additional security as long as their LMR is higher than or equal to 1.0. If a permit holder's LMR falls below 1.0, it will be required to submit a security deposit equal to any amount above which they have been granted on a phased payment schedule. At the request of the OGC, a permit holder may be required to complete a Site-Specific Liability Assessment (SSLA) rather than using general deemed liability cost information. For SSLAs, all scope-of-work items and costs to fully abandon and reclaim the well or facility must be included in the assessment. The SSLA must be completed by a qualified third-party practicing professional. The LMR Manual provides additional detail on conducting an SSLA, as well as providing information and guidance for calculating deemed assets and deemed liabilities based on general costs. A copy of the LMR Manual is provided as Appendix A to the report. A sample LMR report published by the OGC is provided as Appendix B to this report. The recently issued Industry Bulletin 2014-12: Updates to the Liability Management Rating Program is provided as Appendix C to this report.

3.2.3 Well Site and Facility Closure

The OGC will issue a Certificate of Restoration after an independent qualified Reclamation Specialist has verified that surface reclamation meets all provincial requirements. The OGC can return the security if the person has restored the land to pre-development condition, or has an agreement with the landowner and has compensated the landowner for any damage or disturbance of the land.

3.2.3.1 Orphan Wells

The OGC oversees the restoration and remediation of any orphaned sites. There is an Orphan Site Reclamation Fund, which receives industry funding for reclamation of orphan sites and compensate landowners if deemed necessary. This revenue is generated through an orphan site restoration tax. Oil and gas licensees pay $0.03 per 1,000 cubic metres of marketable gas produced and $0.06 per cubic metre of petroleum produced in a production month under this program.

3.2.3.2 Oil and Gas Pipelines

Security is required under the OGAA to build additional pipeline. The OGC will require a permit holder to provide security in the amount as follows:

- For private land- $50,000 CDN per km of the proposed pipeline
- For Crown land- $10,000 CDN per km of the proposed pipeline, up to a maximum of $150,000; with a minimum of $7,500 CDN.

The OGC accepts either cash or an irrevocable letter of credit from a chartered Canadian bank or credit union per Section 25 of the Fee, Levy, and Security Regulation for the above securities.

3.3 Contaminated Sites

3.3.1 Calculation of Securities for Contaminated Sites

Protocol 8 for Contaminated Sites: Security for Contaminated Sites, which was written pursuant to Section 64 of the Environmental Management Act, describes the procedures to be followed when determining if the Ministry of Environment, Director of Waste Management should collect a security deposit for remediation activates for a contaminated site. Section 5 of Protocol 8 describes how the amount of security deposit is calculated for contaminated sites. The calculation procedures include formulas to address remediation that is not progressing as required, how to calculate costs for ongoing management and monitoring, and how to account for the effects of inflation. A copy of this protocol is provided as Appendix D.

3.3.2 Forms of Securities/Financial Assurance Accepted

The Ministry of Environment accepts one or a combination of the following forms of security in the amount specified by the Director of Waste Management:

- Irrevocable letters of credit
- Security deposits, including short-term deposits
- Registered bonds
- Treasury bill notes
- Bank drafts
- Money orders
- Certified cheques
- Any other type of security acceptable to the Director of Waste Management under Protocol 8 (issued by the Minister of Environment).

SOURCES CITED

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APPENDIX A

LIABILITY MANAGEMENT RATING MANUAL

Liability Management Rating Program Manual
January | 2014

Version 2.3

Contents

Manual Revisions

Summary of Revisions

Manual revisions by section are highlighted below.

Applications received on or after the effective date (as indicated in the revision table) will be required to meet the revised application standards.

Effective Date	Section	Description/Rationale
1-Mar-2011	Section 6	Added clarification re: Dispute Process and Site-Specific Liability Assessments
1-July-2013	Section 3	Added content to Gas Processing section (p.10). Added content to Waste Disposal section (p.11).
	Section 6	Added content to Dispute Process section (p.18).
28-Oct-2013	Various	This document has been updated to reflect the PIMS / KERMIT migration. Users are encouraged to review the document in full. For more information regarding this update, please refer to INDB 2013-14 PIMS Update.
16-Jan-2014	Section 5	Added “Security deposits held by the Commission in cash form are not interest bearing” to “Permit Transfer Applications” (p. 15).

1 Preface

Purpose

This manual was created to guide users through the processes and procedures of the Commission's Liability Management Rating (LMR) program. The purpose of the LMR program is to ensure that permit holders are responsible for the financial risks related to their operations. It assists the Commission in determining security deposits required by permit holders to protect against those who may not be capable of meeting abandonment and reclamation obligations.

This manual is not intended to replace applicable legislation; the user is encouraged to read all applicable legislation and regulation and request clarification from Commission staff, if necessary.

Scope

This manual provides information on the processes and requirements within the Commission's legislative authorities; it does not provide information on legal responsibilities outside of the Commission's legislative authorities. It is the responsibility of the applicant or permit holder to know and meet all of its legal responsibilities.

How to Use This Manual

This manual is presented in sections, which are organized chronologically to represent the order of the activities applicants and permit holders must follow when engaging in oil and gas activities.

Beginning with a summary of the LMR program, the manual guides the user through LMR calculations, including the determination of deemed assets and liabilities, to security deposit requirements and dispute processes.

Section 2 **Liability Management Rating** A summary of the LMR program and the equation for calculating a permit holder's rating.

Section 3 **Determination of Assets** A summary of how to calculate a permit holder's deemed assets.

Section 4 **Determination of Liabilities** A summary of how to calculate a permit holder's deemed liabilities, including well and facility specifics.

Section 5 **Security Deposit Requirements** A summary of LMR assessments and the processes related to required security deposits.

Section 6 **Dispute Process** A summary of how to make a formal dispute to a security deposit request.

Additional Guidance

The glossary page of the Commission's website provides a comprehensive list of definitions.

The appendices include documents to be used as references when compiling information required by the Commission.

Other navigational and illustrative elements used in the manual include:

Hyperlinks: Hyperlinked items appear as blue, underlined text. Clicking on a hyperlink takes the user to a document or webpage.

Sidebars: Sidebars highlight important information, including new information, updates, reminders or tips.

Figures: Figures illustrate a function or process, presenting the user with a visual representation.

Tables: Tables organize information into columns and rows for convenient comparison.

Feedback
The Commission is committed to continuous improvement by collecting information on the effectiveness of manuals, forms and guidelines. Stakeholders who would like to comment on Commission documentation may send constructive comments to OGC.Systems@bcogc.ca.

2 Liability Management Rating

The BC Oil and Gas Commission (Commission) has developed a LMR program. The objective of the program is to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. As such, the LMR program will be used by the Commission to assist in determining required security deposits for permit holders under section 30 of the Oil and Gas Activities Act (OGAA).

The LMR is the calculated ratio of deemed assets to deemed liabilities for permit holders. The LMR program is used to identify permit holders whose liabilities exceed assets (a LMR of less than 1.0), and it requires that said permit holders take action to mitigate any financial risks represented by the difference in the calculation.

Liability Management Rating Equation

The LMR is calculated corporately for each permit holder using the following generalized formula:

$$LMR = \frac{\textit{Deemed Assets} + \textit{Security Deposit}}{\textit{Deemed Liabilities}}$$

The LMR is calculated for all wells and facilities registered to a permit holder. Generally speaking, it is the estimated income for a permit holder's operated assets divided by the cost to decommission and reclaim the assets. A permit holder's working interest in a particular well or facility is not considered in the LMR calculation.

Permit holders with a calculated LMR of less than 1.0 will be deemed high risk and reviewed for a security deposit. Permit holders with a calculated LMR equal to or greater than 1.0 will not be reviewed for a security deposit.

A list of permit holders and their respective LMR is updated monthly and posted on the Commission's website.

Any questions regarding the LMR program can be directed to:

Mike Janzen, P.Geo.
Manager, Asset Integrity & Retirement
(250) 419-4464 or mike.janzen@bcogc.ca

3 Determination of Assets

Deemed assets are calculated using the following equation:

Deemed Assets = Annual Volume x Netback x Return Period

A permit holder's overall deemed asset is the sum of calculable assets in production, gas processing, and waste management operations for which it holds permits.

Volumes used in the asset determination presented herein are as reported to the Commission or the Ministry of Finance, Mineral, Oil and Gas Revenue Branch.

Producers

Permit holders with raw production reporting will be subject to the above deemed asset calculation, where:

- *Annual Volume*: A permit holder's annual volume of oil equivalent production (m^3OE), calculated for the previous 12 reporting months
  - Gas volume is converted to oil equivalent through application of:
    - Shrinkage Factor = 0.137
    - Oil Equivalency Factor = 1.73
- *Netback*[1]: Five-year industry rolling average up to 2009
  - Currently equal to $289/$m^3$OE
- *Return Period*: The estimated minimum reserve life, set at three years

Incorporating the above, the detailed deemed asset calculation for producers is as follows:

$\$ = (m^3\ Oil + ((e^3m^3\ Gas * (1 - 0.137))/1.73)) * \$289/m^3 * 3$

[1] Calculated from Statistical Handbook for Canada's Upstream Petroleum Industry, CAPP, 2009

Gas Processing

Permit holders whose assets are primarily in the form of processing raw gas into marketable gas are able to obtain a deemed asset for a designated Gas Plant using the above calculation, where:

- *Annual Volume*: The permit holder's annual volume at the facility inlet, calculated for the most recent 12 reporting months, reported in e^3m^3. A permit holder's own raw gas production will not be included in the inlet volumes, but rather will be included in the Producer asset calculation
- *Netback*: The industry average profit from processing third-party gas per unit gas volume
    - Calculated as the average of all industry-submitted Gas Plant netbacks
    - Currently equal to $14/$e^3m^3$
- *Return Period*: The deemed life of a facility, based on the calculated throughput decline rate over the previous 5 reporting years. The maximum allowable return period is 8.5 years

The throughput decline rate (DR) is calculated using reported inlet gas volumes, where a trend is established to determine whether throughput is generally on the rise or on the decline over the measured period (i.e. a higher or lower deemed life).

Return Period (yrs) = $13e^{-6DR}$

- DR = $[(V_2 - V_1)/V_2 + (V_3 - V_2)/V_3 + (V_4 - V_3)/V_4 + (V_5 - V_4)/V_5] / 4$
    - V = Volume in e^3m^3
    - V_1 is the sum of the most recent 12 reporting months, V_2 is the sum of the previous 12 reporting months, and so on.

Permit holders that wish to receive a deemed asset for a designated Gas Plant must submit a facility-specific netback, upon request by the Commission, using the Facility-Specific Netback Calculation Form. The netback used in determination of the deemed asset is based on an average of all submitted industry Gas Plant netbacks from the 2012 fiscal year (or most recent year-end). Permit holders that chose not to submit a netback will be given a deemed asset of zero. The deemed asset for a Gas Plant will be included in the permit holder's overall LMR calculation.

Waste Management

Permit holders whose assets are primarily in the form of waste management are able to obtain a deemed asset for a designated Disposal Station using the above calculation, where:

- Annual Volume: The permit holder's annual volume of fluid received at a Disposal Station for disposal down-well, calculated for the previous 12 reporting months, reporting in m^3. As volumes are reported by well WA number, the reported volumes will be attributed to the applicable Disposal Station via reported well-facility linkages
- Netback: The industry average profit from receiving, handling, and disposing of waste fluids
    - Calculated as the average of all industry-submitted Disposal Station netbacks
    - Currently equal to $17/$m^3$
- Return Period: The allowable marketable life of a Disposal Station, set at 1.5 years

Permit holders that wish to receive a deemed asset for a designated Disposal Station must submit a Facility-Specific Netback Calculation Form, whereby the linked disposal volumes down-well may be used in calculation. The netback used in determination of the deemed asset is based on an average of all submitted industry Disposal Station netbacks from the 2012 fiscal year (or most recent year-end). Permit holders that chose not to submit a netback will be given a deemed asset of zero for the facility. The deemed asset for a facility will be added to the permit holder's overall LMR calculation.

The industry average netbacks for Gas Plants and Disposal Stations will be valid for a period up to three years.

4 Determination of Liabilities

Deemed liabilities are calculated using the following equation:

Deemed Liabilities = Abandonment Cost + Reclamation Cost

Liability unit costs are assigned on the date of rig release for a well or on the date of construction completion for facilities. Abandonment unit costs for wells include the down-hole plugging of all required zones, as well as the necessary cut and cap work. Abandonment unit costs for facilities include evacuation and dismantling of all equipment, the purging and cutting and capping of all pipelines, as well as the transport of material to a suitable receiving facility. Reclamation unit costs include the remediation of contaminated media, restoration of surface soils and re-vegetation of the site. Unit costs may change throughout the life of a well or facility due to operational changes (i.e., additional completions, re-entries, amendments, etc.). At the Commission's discretion, the deemed liability for a permit may be replaced by the undiscounted cost determined through an operator's accounting for Asset Retirement Obligations.

If a well or facility contains additional contaminated media, beyond which has been considered in the standard liability unit cost, the Commission may opt to calculate a site-specific liability cost for the well and/or facility.

For standard liability unit costs and factors, refer to Appendix B.

Wells with a registered status of "abandoned" and facilities with a registered status of "removed", including all surface decommissioning requirements, will not have the abandonment unit cost included in the liability calculation. Wells and facilities that have been issued a Certificate of Restoration (COR), or wells that were abandoned before the enactment of COR requirements in 1974, are not included in the LMR calculation. However, wells that have been re-entered or require additional remedial activities after the issuance of a COR are included.

An LMR Liability Map has been created to group wells and facilities into three geographic areas: Plains, Montane and Northern Areas. Development considerations of the Liability Map included: ecology, the Agricultural Land Reserve, seasonal access, topography and remoteness. Permit holders that would like to obtain the GIS shapefiles used to create the LMR Liability Map can download the information from the FTP site.

Wells

The deemed liability for a well is defined as the estimated cost to decommission, remediate and reclaim the site. For the purpose of estimating liability for a well, factors such as remoteness, seasonal access, age, fluid type, production history, number of completions, vent flow/gas migration, H_2S and drilling waste have been used to identify risk factors that increase closure costs.

Using information fields that are managed in Commission databases, a well is assigned an abandonment and/or reclamation unit cost, which is linked to its WA number. The total well-based deemed liability for a permit holder is the sum of all WA-specific liabilities. All permits for oil, gas, and water production, injection, and disposal wells, as well as test holes, are included in the LMR calculation.

Facilities

The deemed liability for a facility is defined as the estimated cost to decommission, remove equipment, remediate contaminated media and reclaim the site. Facility liability unit costs use factors such as remoteness, seasonal access, age, fluid type, throughput, equipment and H_2S to identify risk factors that increase closure costs.

Using information fields that are managed in Commission databases, a facility is assigned an abandonment and/or reclamation liability, which is linked to its FacID number. The total deemed facility liability for a permit holder is the sum of all FacID-specific liabilities. All facility permits for gas plants, central dehydrators, batteries, compressor stations, waste disposal stations, satellite batteries and other stations are included in the LMR calculation. Other stations include injection stations, water hubs, shared facilities, and pipeline terminals. Where a combination of facility equipment is processing, or has processed, both oil and gas volumes, liability will be categorized and scaled by the larger of either fluid throughput.

Multi-Well Pad Liability

Where wells share a common lease/pad, reclamation liability will be calculated using a revised method, rather than using the standard costs in the LMR model. The deemed reclamation liability for a multi-well pad will be equal to the largest reclamation unit cost for one of the wells constructed on the site, plus 20% of the reclamation unit cost applicable to each remaining well on the site. The deemed abandonment liability will be equal to the sum of the abandonment unit costs for all wells on the site and will not be reduced.

Permit holders that would like to report multi-well pads to the Commission should use the Multi-Well Pad Notification Form.

Problem Sites

For the purposes of limiting risk to public safety and the environment, reducing exposure to high-liability sites, and ensuring compliance with regulations, a well or associated facility may be deemed a Problem Site by the Commission. Problem Sites may exist where the standard deemed liability cost does not capture the site-specific cost to abandon and reclaim a site. Factors such as problematic surface casing vent flows, gas migration and significant soil and/or groundwater contamination can increase liability costs above the model assumptions.

The Commission may initiate a review of a well or facility for potential Problem Site designation when an inspection gives reason to suspect that standard deemed liability costs are below the site-specific liability cost, or if a site is found to be in non-compliance with the regulations. If a review is initiated, the Commission gathers information on the environmental status of the site. If information is insufficient to determine environmental risk and revise the liability cost, the Commission may request that a site-specific liability assessment be completed by the permit holder (see Dispute Process). If the results of the review indicate that the required remedial activities are acceptable and the permit holder has planned to address the liability accordingly, no Problem Site designation will be sought. However, the Commission may require that:

- A remedial plan be put in place if one does not exist
- The well or facility be designated a Problem Site if the plan insufficiently addresses environmental risks or regulatory closure

The Commission may choose to designate a well or facility as a Problem Site when any of the following occur:

- Site-specific liability and risk exceeds standard deemed liability assumptions and may not be remediated in a timely manner, or in accordance with the regulations
- A site is classified as *Priority* using the Upstream Oil and Gas Site Classification Tool
- A site exhibits environmental impacts that cannot be remediated to numerical soil or water standards
- The extent of environmental impacts extends beyond the legal boundaries of a site

If a well or facility is designated a Problem Site, the permit holder is required to submit a security deposit equal to the liability costs determined by the Commission, or through the submission of a site-specific liability assessment. A Problem Site security deposit requires payment within 30 days from the date of request. As an alternative to a security deposit, the permit holder may, within the 30 days, request that the Commission accept a Liability Management Plan (LMP), which outlines the permit holder's planned remedial activities and schedule to address the causes for the Problem Site designation. If the Commission approves the request, the timeline for delivery of the LMP will be decided upon and the security deposit requirement will be rescinded until the due date for the LMP. If the permit holder does not carry out the activities within the LMP, a security deposit will be reassessed.

5 Security Deposit Requirements

Permit holders will be subject to regular assessments of their LMR. The LMR is the sum of the deemed assets calculated through production, processing, and disposal volumes, divided by the sum of the deemed liabilities for well and facility permits. Should a permit holder's overall LMR fall below 1.0, a security deposit will be required in the amount necessary to return the LMR to 1.0.

New Permit Holders

Permit holders who are applying for their first well or facility permit or permit transfer may be required to achieve a security-adjusted LMR of 1.0. A security deposit is calculated based on post-application inventory. If a security deposit is based on the permit holder's first well application, the amount is determined by the factors outlined in the application.

Bi-Monthly Assessments

The Commission completes LMR assessments on a monthly basis, at which time the deemed asset and liability estimates are recalculated to provide updated LMRs for all permit holders. However, assessments for security deposits will be made on a bi-monthly basis. Should a permit holder's LMR drop below 1.0 at the time of an assessment, a security deposit will be required within 30 days from the date of request to return the LMR to 1.0.

If a permit holder is on a phased payment schedule, they will not be required to submit an additional security should their LMR remain the same or increase. However, if a permit holder's LMR decreases during a bi-monthly assessment, they will be required to submit a security deposit equal to any amount above which they have been granted on a phased payment schedule.

Permit Transfer Applications

Upon receipt of an application for a permit transfer of one or more wells and/or facilities, both the transferor and the transferee will be subject to a LMR review. The applicant or permit holder involved in the transaction is required to submit a security deposit if their post-transfer LMR drops below 1.0The amount of the required security deposit will be the difference between the applicant's post-transfer deemed liabilities and assets, to be submitted within 30 days from the date of request.

At the request of a permit holder, the Commission may return all or part of a security if the official is satisfied that all or part of the security is not required to secure the permit holder's obligations under OGAA or the permit holder's permits or authorizations.

Permit holders can make the request to:

Liability.Management@bcogc.ca

Security deposits submitted in cash or as an irrevocable letter of credit in a format that is satisfactory to the Commission will be accepted. Security deposits held by the Commission in cash form are not interest bearing.

Non-Compliance

Permit holders who fail to submit required security deposits within the allotted timeframe may be in noncompliance with Section 30 of OGAA. If the security deposit was required to approve a permit transfer application, the application will not be approved. If the security deposit was required under an initial or bi-monthly assessment, additional compliance actions are taken against the permit holder, which may result in the cancellation of permits or orders to cease operations.

6 Dispute Process

Dispute Process

Permit holders may dispute a required security deposit by submitting a dispute request to the Commission. A dispute request is based on the permit holder's specific inventory and must support revised asset and liability calculations. The revised deemed asset calculation for producers must include the permit holder's own netback, calculated as production income minus operating expenses and royalties, using the Permit Holder Netback Calculation Form. In the case of gas processing or waste management operators, a facility-specific netback must be submitted for each Gas Plant or Disposal Station using the Facility-Specific Netback Calculation Form. The revised deemed liability calculation for all permit holders must be based on a site-specific liability assessment for each of the wells and facilities registered to the permit holder in accordance with the following section.

Dispute requests must be completed by a practicing professional who can provide adequate assurance to the Commission that they are qualified to perform the asset and liability revisions. The dispute application must also be reviewed and signed by the permit holder's Chief Financial Officer (or equivalent).

The permit holder or applicant in a dispute request must provide sufficient information and supporting documents to enable the Commission to understand the dispute, arguments and requested remedies.

Dispute requests can be made to:

Liability.Management@bcogc.ca

or

BC Oil and Gas Commission
Environmental Liability Rating
300 – 398 Harbour Road
Victoria, B.C. V9A 0B7

Site-Specific Liability Assessments

At the request of the Commission, a permit holder may be required to complete a Site-Specific Liability Assessment for one or more permits to be used in the calculation of a permit holder's LMR or, in the case of a Problem Site, for the determination of a security deposit. The assessment must include all scope-of-work items and costs to fully abandon and reclaim the well or facility and must be completed by a third-party practicing professional who can provide adequate assurance to the Commission that they are qualified to complete the assessment.

In creating a scope of work for estimating abandonment costs, an inventory of all on-site equipment must be taken. The abandonment cost must therefore include the cost to suspend, evacuate, remove and transport all on-site equipment to a suitable facility. It must also include the cost to repair any surface casing vent flow or gas migration issues, as well as all necessary down-hole plugging and cut and cap requirements. Costs must be consistent with a work plan, based on the Commission's Well Completion, Maintenance and Abandonment Guideline and Facility Application and Operations Manual.

The reclamation scope of work and costs should be estimated following the completion of a Phase II Environmental Site Assessment (Canadian Standards Association) or Stage II Detailed Site Investigation (BC Ministry of Environment). All potentially-affected environmental media must be assessed. Contaminated media must be sufficiently characterized and delineated such that volumes requiring remediation can be quantified. Costs to complete the remediation of contaminated media should be estimated using proven remediation or risk-assessment methodology that will result in soil and/or groundwater that meets applicable, risk-based environmental quality guidelines. Surface soil and vegetation reestablishment costs must include all assessment and monitoring costs following site work. All critical pathway items, including the preparation of Certificate of Restoration Part 1 and Part 2, must be followed and included in the estimate.

Appendix A: Liability Map

Appendix B: Liability Costs

Well Abandonment Cost Model

Classification - Status	Depth	Liability Cost		
		Plains Area	Montane Area	Northern Area
All Wells - Drilled/Cased	-	$7,500	$10,000	$12,500
Sweet Well - Completed/Active/Inactive	0 - 1000 m	$42,300	$46,200	$56,600
	1000 - 2000 m	$54,500	$58,700	$71,200
	2000 - 3000 m	$68,500	$73,100	$88,000
	> 3000 m	$82,600	$87,500	$104,900
Sour Well (H2S >1%) - Completed/Active/Inactive	0 - 1000 m	$54,500	$59,800	$74,700
	1000 - 2000 m	$68,900	$75,600	$94,400
	2000 - 3000 m	$85,100	$93,200	$116,500
	> 3000 m	$100,800	$110,900	$138,600
Source Water Well	0 - 150 m	$4,000	$4,500	$5,000
	151 - 300 m	$8,000	$9,000	$10,000
	> 300 m	$25,000	$27,500	$30,000
Legacy Premium (Pre 1985)	-	$25,000	$25,000	$25,000
Vent Flow/Gas Migration	-	$62,400	$71,100	$87,200
Additional Completion Zones	-	Add 30% per zone		

Well Reclamation Cost Model

Classification - Status	Age	Liability Cost		
		Plains Area	Montane Area	Northern Area
All Wells - Never Produced/Injected	-	$30,700	$41,900	$46,100
Gas Well - Active/Inactive/Abandoned	Post 1990	$40,600	$52,700	$58,000
	Pre 1990	$69,800	$88,600	$103,000
Oil or Condensate Well - Active/Inactive/Abandoned	Post 1990	$52,500	$67,000	$74,100
	Pre 1990	$89,600	$106,000	$128,300
Injection or Disposal Well - Active/Inactive/Abandoned	Post 1990	$52,500	$67,000	$74,100
	Pre 1990	$89,600	$106,000	$128,300
Cancelled Well w/ Surface Disturbance	-	$10,000	$12,000	$15,000
Water Well	-	Exempt		
Onsite Sump Contamination	-	$90/m3	$94/m3	$98/m3
Additional Contaminated Media	-	Site Specific Cost		

Facility Liability Cost Model

Facility Type	Design	Abandonment Liability Cost			Reclamation Liability Cost		
		Plains Area	Montane Area	Northern Area	Plains Area	Montane Area	Northern Area
Gas Processessing Facility (Plant Designation)	0 - 999 e3m3/d	$159,400	$175,300	$192,900	$327,000	$359,700	$395,700
	1000 - 2999 e3m3/d	$307,600	$338,400	$372,200	$522,400	$574,600	$632,100
	3000 - 4999 e3m3/d	$413,800	$455,200	$500,700	$692,300	$761,500	$837,700
	>5000 e3m3/d	$527,000	$579,700	$638,700	$1,103,700	$1,214,100	$1,335,500
Gas Dehydration Facility	0 - 299 e3m3/d	$43,800	$48,200	$53,000	$80,400	$88,500	$97,300
	300 - 1499 e3m3/d	$109,600	$120,500	$132,500	$180,200	$198,200	$218,000
	>1500 e3m3/d	$197,200	$217,000	$238,700	$298,100	$327,900	$360,700
Compressor Stations	0 - 599 KW	$38,500	$42,400	$46,600	$56,700	$62,400	$68,600
	600 - 2999 KW	$93,900	$103,300	$113,600	$130,500	$143,500	$157,900
	>3000 KW	$174,000	$191,400	$210,500	$225,000	$247,500	$272,300
Battery Sites	0 - 49 m3/d	$40,900	$45,000	$49,500	$82,600	$90,900	$99,900
	50 - 499 m3/d	$112,700	$124,000	$136,400	$176,300	$193,900	$213,300
	500- 1500 m3/d	$201,900	$222,100	$244,300	$275,100	$302,600	$332,900
	>1500 m3/d	$291,800	$321,000	$353,100	$363,600	$399,900	$440,000
Battery Sites w/ Seperation, Compression, Injection, and/or Disposal Equipment	0 - 49 m3/d	$59,400	$65,300	$71,900	$111,900	$123,100	$135,400
	50 - 499 m3/d	$131,200	$144,300	$158,800	$203,000	$223,300	$245,600
	500 - 1500 m3/d	$245,400	$269,900	$296,900	$325,600	$358,200	$394,000
	>1500 m3/d	$335,700	$369,300	$406,200	$414,100	$455,500	$501,100
Satellite Batteries	0 - 99 m3/d	$41,000	$45,100	$49,600	$75,000	$82,500	$90,800
	>100 m3/d	$61,500	$67,600	$74,400	$112,500	$123,700	$136,200
Other Stations	-	$33,000	$36,300	$39,900	$69,000	$75,900	$83,500
H2S Premium (>1%)	-	Add 10%			-		
Legacy Premium (Pre 1990)	-	Add 20%			Add 30%		
Additional Contaminated Media	-	-			Site Specific Cost		

Definitions

Gas Processing Facility – Gas plant sites with dehydration, refridgeration, sweetening, absorbtion, and/or fractionation capabilities.
Battery Sites w/ Separation, Compression, Injection, and/or Disposal Equipment include facilities classified as Water Disposal Stations.
Other Stations – Upstream oil and gas faciliy sites include injection stations, water hubs, shared facilities, and pipeline terminals.
KW power is equal to total of all compressors.

Appendix C: Netback Calculation Forms

BC Oil & Gas COMMISSION

FACILITY SPECIFIC NETBACK CALCULATION
(gas processing and waste disposal operations)

300 - 398 Harbour Rd
Victoria, B.C. V9A 0B7
Phone: (250) 419-4400

Date Received

Submit to: Liability.Management@bcogc.ca

Permit Holder Contact Information

Permit holder name: ID: Phone:
Mailing address: Fax:
Contact: Email address: Direct phone:

Calculation - individual facility netback

Fiscal year end: *All blue boxes to be entered for each processing or disposal facility under permit

		Facility 1	Facility 2	Facility 3	Facility 4	Facility 5	Facility 6	Facility 7
	Facility code #							
	Type of facility							
Year:	Revenue ($)							
	Operating costs ($)							
	Royalties ($)							
	Net Revenue ($)	$0	$0	$0	$0	$0	$0	$0
	Throughput (m^3 or e^3m^3)							
	Netback ($\$/m^3$ or $\$/e^3m^3$)	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**

Notes:
- Information should be submitted for the most recent fiscal (un-audited) year, from British Columbia (BC) operations only
- All supporting documentation must be provided with the submission
- 'Operating costs' are all costs of doing business, including levies, administration, management, transportation, and operational costs. Not including taxes, depreciation, depletion or accretion, loss on investments or risk management, interest paid or stock compensation. Royalties reported separately.
- Do not include the portion of costs attributed to the processing of own raw gas (if any)
- Revenue and expenses generated from atypical facility activity should be excluded from calculation
- Throughput provided must correspond to the same accounting period as the fiscal year-end statements provided with submission
- Throughput includes only third party volumes that generated revenue, volumes from or as a by-product of own processes are to be excludec
- Disposal facilities throughput is to include water volumes only
- Facility specific netbacks must be submitted for approval every year by the end of February and are valid for the following 12months. Subsequest year submissions must be received before the end of January. Failure to submit or obtain approval on a facility's netback will result in a Netback of $0, and the permit-holder will be required to provide a security deposit equal to 100% of the facility's deemed liability.

Sign off

I certify the information submitted is accurate and correct to the best of my knowledge

Name:
Position: (Corporate Officer only) Date:

BC Oil & Gas COMMISSION

PERMIT HOLDER NETBACK CALCULATION
300 - 398 Harbour Rd
Victoria, B.C. V9A 0B7
Phone: (250) 419-4400

Date Received

Submit Form | Reset Form

Permit Holder Contact Information

Permit Holder name: | Contact:
Permit Holder ID: | Direct dial phone:
Mailing address: | Email:
Phone: | Fax:

Calculation Data

Year-end:

	2010	2009	2008
Oil Revenue ($)			
Gas Revenue ($)			
Operating costs ($)			
Royalties ($)			
Net Revenue ($)	0.00	0.00	0.00
Oil Production (m^3)	0.00	0.00	0.00
Gas Production (Km^3)	0.00	0.00	0.00
Gas Oil Equivalency (m^3)	0.00	0.00	0.00
Total OE Production (m3)	0.00	0.00	0.00
Annual Netback ($\$/m^3OE$)	0.00	0.00	0.00

3yr AVG. Netback ($\$/m^3OE$)	0.00

Notes:
- OE = Oil equivalency
- Annual Netback should be submitted for the three most recent audited years
- All supporting documentation must be provided with the submission
- Industry averages will be used for years not submitted
- Data from British Columbia (BC) operations only
- Condensate and Natural Gas Liquids (NGL's) are to be converted to OE and included in oil reporting
- 'Operating costs' are all costs of doing business, including levies, administration, management, transportation, production costs, and taxes. Not including depreciation, depletion or accretion, loss on investments or risk management, interest paid, or stock compensation.

Sign off

I certify the information submitted is accurate and correct to the best of my knowledge

Name:

Position:

Date:

Calculating oil and gas production

**Blue boxes must be entered

	OIL		GAS	
2010	bbls/d		mcf/d	
	bbls year	0	mcf year	0
	Total m^3	0	Total Km^3	0
2009	bbls/d		mcf/d	
	bbls year	0	mcf year	0
	Total m^3	0	Total Km^3	0
2008	bbls/d		mcf/d	
	bbls year	0	mcf year	0
	Total m^3	0	Total Km^3	0

bbls/d	Barrels a day
mcf/d	Thousand cubic feet a day

Appendix D: Multi-Well Pad Notification

BC Oil & Gas COMMISSION

MULTI-WELL PAD NOTIFICATION
300 - 398 Harbour Rd
Victoria, B.C. V9A 0B7
Phone: (250) 419-4400

Date Received

Submit to: Liability.Management@BCOGC.ca

For notification when wells of a single Permit Holder share a single surface lease/pad.
An individual form must be submitted for each lease/pad.

Permit Holder Contact Information

Permit Holder name:		Contact:
Permit Holder ID:		Direct dial phone:
Mailing address:		Email address:
Phone:	Fax:	

Included inventory

The following wells are located on the same lease/pad:

WA number	Well name	Surface location

Note: Sharing a common NTS/DLS location is not a pre-requisite for a shared surface lease.
The Commission will review notifications for accuracy.

A lease is defined as a designated area of land with an associated lease, easement, right of way or other agreement with the land owner authorizing the entry, occupation or use of the land for the purpose of carrying out an oil and gas related activity or to comply with an order from the Commission.

Sign off

I certify the information submitted is accurate and correct to the best of my knowledge

Name: ____________________

Position: ____________________

Date: ____________________

APPENDIX B

SAMPLE LIABILITY MANAGMENT RATING MONTHLY REPORT

2014AUG14
OGCR887

Liability Management Monthly Summary Report

Producers

Each permit holder will have their Liability Management Rating (LMR) assessed on a monthly basis and reported here.

Oper ID	Operator Name	Security	Security Adjusted LMR
0076	1023095 Alberta Ltd.	*	1.00
0833	1089814 Alberta Ltd.	*	0.46
0682	1333002 Alberta Ltd.	*	2.48
0974	1696719 Alberta Ltd.	*	1.00
0198	Aduro Resources Ltd.		4.37
0727	Advantage Oil & Gas Ltd.	*	1.00
0150	Anadime Energy Inc.	*	0.08
0314	Apache Canada Ltd.		16.71
0435	Arawn Energy Ltd.	*	1.01
0057	ARC Resources Ltd.	*	23.64
0731	Arsenal Energy Inc.	*	4.07
0230	Artek Exploration Ltd.	*	14.26
0322	Baytex Energy Ltd.		1.83
0160	Bellatrix Exploration Ltd.	*	1.00
0955	Black Swan Energy Ltd.		13.42
0528	BLZ Energy Ltd.	*	0.34
0047	Bonavista Energy Corporation		2.67
0824	Bonterra Energy Corp.	*	2.19
0964	BP Canada Energy Group ULC	*	1.88
0013	Calpine Canada Resources Company	*	-
0107	Calver Resources Inc.	*	0.75
0200	Canadian Arctic Gas Ltd.	*	-
0237	Canadian Natural Resources Limited		3.70
0086	Canadian Spirit Resources Inc.	*	1.00
0458	Canbriam Energy Inc.		49.23
0710	Canetic ABC Acquisitionco Ltd.		-
0954	Carmel Bay Exploration Ltd.		1.67
0950	Carnaby Energy Ltd.		1.59
0219	CEP International Petroleum Ltd.	*	-
0201	Cequence Energy Ltd.	*	3.31
0269	Chevron Canada Limited	*	1.00
0933	Chinook Energy (2010) Inc.	*	1.91
0273	Coastal Resources Limited	*	3.37
0519	Connacher Oil and Gas Limited	*	0.91
0826	ConocoPhillips Canada Operations Ltd.	*	3.37
0416	ConocoPhillips Canada Resources Corp.		7.05
0033	Crescent Point Energy Corp.	*	1.00
0092	Crew Energy Inc.	*	11.78
0972	Crimson Oil & Gas Ltd.	*	0.61
0199	Crocotta Energy Inc.	*	14.17
0410	DEJOUR ENERGY (ALBERTA) LTD.	*	6.18
0351	Delphi Energy Corp.	*	3.42
0440	Devon Canada Corporation	*	2.57
0367	Devon NEC Corporation	*	3.86

Oper ID	Operator Name	Security	Security Adjusted LMR
0106	Dewinton Oilfield Trading Company Inc.	*	1.00
0090	Dewpoint Resources Ltd.	*	1.00
0988	Direct Energy Marketing Limited		5.04
0171	Dolomite Energy Inc.	*	1.00
0143	Ember Resources Inc.	*	0.92
0619	EnCana Corporation	*	35.04
0990	Endurance B.C. Gas Ltd.		3.77
0934	Enerplus Corporation		2.95
0334	EOG Resources Canada Inc.		11.94
0551	ExxonMobil Canada Energy	*	1.75
0344	Faro Petroleum Ltd.	*	-
0325	Fortaleza Energy Inc.		3.24
0443	Gear Energy Ltd.	*	1.00
0999	Glenogle Energy Inc.		1.87
0387	Grizzly Resources Ltd.	*	1.00
0846	GS E&R Canada Inc.		2.84
0401	Guardian Exploration Inc.	*	1.00
0369	Harvest Operations Corp.	*	3.60
0968	Hemisphere Energy Corporation	*	1.12
0578	Hunt Oil Company of Canada, Inc.	*	1.22
1002	Huron Resources Corp.	*	1.00
0454	Husky Oil Operations Limited	*	7.02
0850	Imperial Oil Resources Limited	*	17.98
0477	Ish Energy Ltd.	*	1.66
0480	Joffre Resources Ltd.	*	-
0487	Kaiser Energy Ltd.	*	-
0486	Kaiser-Francis Oil Company of Canada	*	-
0006	Kanati Energy Incorporated	*	0.49
0490	Kerr-McGee Canada Ltd.	*	-
0979	Koch Oil Sands Operating ULC	*	1.00
0433	Kodiak Bear Energy, Inc.	*	1.28
0196	KXL Exploration Ltd.	*	1.66
0834	Legacy Oil + Gas Inc.	*	3.14
0142	Lightstream Resources Ltd.		1.17
0065	Lone Pine Resources Canada Ltd.	*	2.54
0082	Mancal Energy Inc.	*	1.01
0445	MFC Energy Corporation	*	1.08
0565	Murphy Oil Company Ltd.		30.50
1000	Nabors Drilling Canada Limited	*	16.07
0455	New Shoshoni Ventures Ltd.	*	0.55
0711	Nexen Energy ULC	*	55.84
0984	Norcan Energy Corporation	*	6.09
0125	Northpine Energy Ltd.	*	0.11
0977	Northpoint Resources Ltd.		8.98
0828	NuVista Energy Ltd.	*	2.78
0556	Nytis Exploration Company Inc.	*	1.00
0602	Ocelot Industries Ltd.		-
0517	Omers Energy Inc.	*	1.52
0462	Painted Pony Petroleum Ltd.	*	25.41
		*	2.57

Oper ID	Operator Name	Security	Security Adjusted LMR
0631	Paramount Resources Ltd.		
0208	Pavilion Energy Corp.		1.24
0639	Pengrowth Energy Corporation	*	2.00
0642	Penn West Petroleum Ltd.		3.18
0213	Pennine Petroleum Corporation	*	2.96
0641	Pensionfund Energy Resources Limited	*	-
0204	Polar Star Canadian Oil and Gas, Inc.	*	2.17
0187	Procyon Energy Corp.		1.69
0691	Progress Energy Canada Ltd.	*	12.58
0994	Quattro Exploration and Production Ltd.	*	3.62
0544	Quicksilver Resources Canada Inc.	*	76.74
0936	Red Rock Projects Inc.	*	0.75
0561	Richlyn Energy Ltd.	*	1.00
0983	Saguaro Resources Ltd.		2.66
0742	Shell Canada Limited	*	21.51
0967	Shiningstar Energy Ltd	*	1.00
0939	Shoreline Energy Corp.	*	3.93
0746	Signalta Resources Limited	*	1.78
0374	Sinopec Daylight Energy Ltd.	*	3.59
0564	South Peace Parkland Ltd.	*	1.34
0976	Spoke Resources Ltd.	*	23.03
0124	Spyglass Resources Corp.		1.69
0759	Starvest Capital Inc.	*	-
0132	Steppe Petroleum Inc.	*	3.91
0952	Storm Cat Energy Canada Inc.	*	0.97
0562	Storm Gas Resource Corp.		5.07
0891	Storm Resources Ltd.		21.18
0998	Success Energy Ltd.		1.27
1001	Sukunka Natural Resources Inc.		39.14
0757	Sullivan and Company	*	0.24
0963	Sun Oil Fund Ltd.	*	0.97
0769	Suncor Energy Inc.		5.57
0771	Superman Resources Inc.	*	1.00
0127	Talisman Energy Inc.	*	12.67
0981	Tallahassee Resources Inc.		-
0390	Tamarack Acquisition Corp.	*	1.00
0606	TAQA North Ltd.		2.20
0392	Tenaka Drilling Consortium Ltd.	*	0.45
0794	Terra Energy Corp.	*	2.47
0831	Tourmaline Oil Corp.	*	42.10
0265	Trans-Dominion Energy Corp.	*	0.18
0207	Transaction Oil & Gas Ventures Inc.	*	1.14
0697	Transeuro Beaver River Inc.	*	0.72
0893	Trilogy Resources Ltd.	*	1.00
0414	TriOil Resources Ltd.	*	2.19
0043	Twin Butte Energy Ltd.	*	1.21
0726	UGR Blair Creek Ltd.	*	1.81
0881	Unocal Canada Limited		-
0978	Venturion Oil Limited		5.60
			1.60

Oper ID	Operator Name	Security	Security Adjusted LMR
1111	Whitecap Resources Inc.		
0896	Windfire Resources Ltd.	*	7.26
0389	Yoho Resources Inc.		2.36
0428	Zargon Oil & Gas Ltd.	*	1.00

Summary Information

Industry LMR average:	**6.25**
Industry LMR median:	**1.96**
Total producer asset value:	**$ 20,795,750,729.86**
Total producer liability value:	**$ 2,612,173,064.00**

* indicates security held.
- indicates an operator with no net deemed assets and/or liabilities under the LMR calculation.

2014AUG14
OGCR887

Liability Management Rating Summary Report

Non-Producers

Each permit holder will have their Liability Management Rating (LMR) assessed on a monthly basis and reported here.

Oper ID	Operator Name	Security Held	Security Adjusted LMR
0953	Aitken Creek Gas Storage ULC	*	149.90
	Aitken Creek Gas Storage ULC DO NOT USE		-
0997	Albright Flush Systems Ltd.		-
0094	Alcan Fluid Disposal Ltd.	*	0.69
0391	Altagas Holdings Inc.		276.18
0439	AltaGas Ltd.		60.85
0832	Aux Sable Canada Ltd.		63.76
0845	C.F. Wright Farms Ltd.	*	-
6004	Canadian Forest Products Ltd.		-
0841	Cancen Oil Processors B.C. Inc.	*	0.25
0257	Central Treating Ltd.		-
9269	Chevron Canada Limited - Burnaby		-
0311	Dynamic Oil & Gas, Inc.		-
0975	Enbridge G and P Canada Inc.	*	1.00
5203	FortisBC Energy (Vancouver Island) Inc.		-
5085	FortisBC Energy Inc.		-
8083	Geological Survey of Canada		-
0465	Imperial Metals Corporation	*	-
0464	Imperial Oil Limited		-
1004	Integrity Processing Inc.	*	1.46
0184	Keyera Energy Ltd.	*	23.40
0496	Koch Oil Co. Ltd.		-
0577	Newalta Corporation		1.47
0000	No Operator or Non-Active Operator		-
0598	Novagas Canada Ltd.		-
2011	Orphan Fund		-
0625	Pacific Northern Gas (N.E.) Ltd.		-
8075	Pacific Northern Gas Ltd.		-
3422	Pacific Trail Pipelines Management Inc.		-
0545	Pembina NGL Corporation	*	1.00
0361	Pembina Pipeline Corporation		-
0900	Plateau Pipe Line Ltd.		-
0530	Secure Energy Services Inc.	*	5.29
0725	Spectra Energy CCS Services Inc.	*	1.01
0229	Spectra Energy Midstream Corporation	*	48.87
	TCPL Resources Ltd.		-
0342	Teck Coal Limited		-
0364	Tervita Corporation	*	2.14
8024	Trans Mountain (Jet Fuel) Inc.		-
0960	Veresen Energy Infrastructure Inc.		53.02
0409	WGSI Holdings Corporation	*	0.54

Summary Information		
Industry LMR average:		40.63705882353
Industry LMR median:		2.14
Total producter asset value:	$	1,956,111,488.75
Total producer liability value:	$	38,496,577.00

* indicates security held.
- indicates an operator with no net deemed assets and/or liabilities under the LMR calculation.

APPENDIX C

INDUSTRY BULLETIN 2014-12: UPDATES TO THE LIABILITY MANAGEMENT RATING PROGRAM

BC Oil & Gas COMMISSION

INDUSTRY BULLETIN
2014-12

September 4, 2014

Updates to the Liability Management Rating Program

The BC Oil and Gas Commission (Commission) is implementing updates to the calculation parameters used to determine production assets in the Liability Management Rating (LMR) program. The current parameters have remained unchanged since the implementation of the LMR program in October 2010.

The calculation parameters are determined by a five-year industry rolling average, using data from the Canadian Association of Petroleum Producers Statistical Handbook. The current parameters are calculated from 2005 to 2009 data. The most recent data available is up to 2012. The current parameters contain financial data that is largely inflated above current gas prices. The proposed update, using 2008 to 2012 data, better reflects market conditions and provides the Commission with updated tools to monitor industry liability exposure. The table below outlines the proposed parameter updates.

Calculation Parameters	Current (2005-2009)	Proposed (2008-2012)
Shrinkage Factor	0.137	0.125
Oil Equivalency Factor	1.73	3.17
Netback	289	320

An analysis of the impact of proposed parameter updates to permit holders with producing assets was conducted in May 2014. It revealed the calculated production assets of 92 per cent of operators would decrease and the remaining eight per cent would see an increase. Unsecured liability, which is the amount of required security calculated in the LMR program, will increase due to the changes. The impact of these effects is outlined in the following table.

Measurement	Current (2005-2009)	Proposed (2008-2012)
Average LMR	6.21	4.25
Median LMR	2.13	1.69
# of producers with LMR <1.0	17	21
Unsecured Liability	$7,638,660	$11,835,438

The updated calculation parameters are planned to become effective in November 2014. In the future, annual updates of asset parameters will be automatically implemented as the data becomes available. For more information see the LMR webpage.

Comments and questions will be accepted until Oct. 3, 2014 and may be directed to:

Mike Janzen
Manager, Asset Integrity and Retirement
BC Oil and Gas Commission
Mike.Janzen@bcogc.ca
250-419-4464

APPENDIX D

PROTOCOL 8 FOR CONTAMINATED SITES: SECURITY FOR CONTAMINATED SITES ISSUED BY THE MINISTRY OF ENVIRONMENT

British Columbia — The Best Place on Earth | Ministry of Environment

PROTOCOL 8
FOR CONTAMINATED SITES

Security for Contaminated Sites

Prepared pursuant to Section 64 of the
Environmental Management Act

Approved:	J. E. Hofweber	November 19, 2007
	Director of Waste Management	Date

1.0 Definitions

"Act" means the *Environmental Management Act.*

"contaminated sites legal instrument" includes, but is not limited to, an Approval in Principle, Certificate of Compliance, Remediation Order and Voluntary Remediation Agreement, as defined under the Act.

"financial risk" means the risk to government of incurring financial costs to remediate contaminated sites where persons are unwilling or unable to fund remediation.

"financial security" means one, or a combination, of the following in the amount and under terms as specified by the Director:

- irrevocable letters of credit,
- security deposits including short-term deposits,
- registered bonds,
- treasury bill notes,
- bank drafts,
- money orders,
- certified cheques, and
- any other type of security acceptable to the Director under this Protocol.

"Ministry" means the Ministry of Environment.

"one-time capital costs" means those costs associated with purchase of equipment, installation of equipment, construction of buildings and other permanent structures, one-time consultant services, architect services, laboratory expenses, fencing, hauling, excavation, costs of expert advice, costs of environmental engineers, etc. which normally occur at the beginning of the remediation process.

"periodic costs" means those costs expected to occur less frequently than annually but at predictable periods, which generally occur after the initial one-time capital costs have been incurred and relate to costs such as capital improvements to existing structures, costs of a five year review, payment for external experts and contractors (e.g. engineering advice to maintain the remedial option), laboratory costs, periodic soil testing, inspection, etc.

"recurring costs" means those costs for management and monitoring, labour, materials, ongoing contract services, performance and site monitoring, offsite treatment and disposal, project management, insurance, technical support, etc., that may recur from year to year and are expressed on an annual basis.

"Regulation" means the Contaminated Sites Regulation (B.C. Reg. 375/96).

“security” means the guarantee of an undertaking to address actual and potential impacts at a high risk contaminated site, and may include financial security, and real and personal property.

A number of terms used in this Protocol have the same meaning they are provided in the Act and Regulation. These include “Approval in Principle”, “contaminated site”, “Certificate of Compliance”, “Director”, “Remediation Order”, “responsible person”, and “Voluntary Remediation Agreement”.

2.0 General

2.1 Legal and regulatory authority

Provisions for security under the contaminated sites regime are summarized in Appendix 1 of this Protocol.

2.2 Purpose

Security can be used as a tool by the ministry to manage the financial risks that may be associated with contaminated sites in the context of issuing a contaminated sites legal instrument. Financial risk to the Province can occur if there is a possibility that the Province may incur contaminated site remediation costs for the protection of the environment or human health, or for the restoration or remediation of the environment.

2.3 Guiding principles

The following principles guide the application of this security Protocol:

- A Director is responsible for determining whether security is required, and if so the amount and form of security.
- This Protocol serves as guidance to a Director and is not intended to be binding.
- Each site presents a unique set of circumstances which shall be considered when a Director is determining security requirements.
- Security shall be required only for sites a Director considers high risk.
- In determining the security requirements for a site, security precedents set by the ministry shall be reviewed to promote consistent decision making.
- This Protocol is not intended to act as a barrier to persons performing timely remediation or to providing security to the ministry voluntarily.
- Any required security shall be subject to review when requested by either a Director or the person posting the security.

- Any decision by a Director not to require security or to require or approve a particular form of security for a site shall be subject to review if the conditions relevant to the requirements for security change significantly.
- Government is often exposed to some financial risk so it is unreasonable to attempt to reduce this risk to zero.
- Security requirements shall be consistent, equitable and effective.
- Financial security shall be taken in preference to security in the form of real and/or personal property. If a person cannot or will not provide financial security required by a Director, then real and/or personal property may be taken.
- Security is not typically needed for remediation that is currently being conducted by a person in a manner acceptable to a Director. This does not preclude a Director from requiring security for ongoing management and monitoring costs when remediation is being carried out at high risk contaminated sites.

3.0 Whether security is required

Subject to the guiding principles in section 2.3, the steps below shall be followed to determine if security is required for a contaminated site in the context of issuing a contaminated sites legal instrument. They are shown in the decision tree in Figure 1.

Step 1: Decision: Is the site a high risk contaminated site?

Security will only be required for contaminated sites that a Director considers to pose a high risk. Evidence that a site is not a high risk site shall be submitted to, checked by, and approved by a Director in order for the exemption to apply.

Step 2: Decision: Is security in place under the *Mines Act*?

If a site is subject to a permit under the *Mines Act*, administered by the Ministry of Energy, Mines and Petroleum Resources (MEMPR), then, unless specifically requested by MEMPR to review the *Mines Act* security, the site would not be subject to a requirement for security under the Act.

Step 3: Decision: Is the only responsible person a government body?

As a general rule, government bodies, including a federal, provincial or municipal body, an agency or ministry of the Crown in right of Canada or British Columbia or an agency of a municipality, are exempt from the requirement for security under this Protocol. However, a request for security from a government agency would be appropriate when:

- the government body is part of a pool of responsible persons or;
- the government body is a Crown corporation which has been determined to be a responsible person in its own right.

Step 4: Decision: Has remediation been approved for the site?

Has remediation been approved by a ministry official under a contaminated sites legal instrument, including a Remediation Order? If not, the Director may determine that security is required at this time and may specify the form, amount and any conditions. Security required in this step shall be calculated using formula 1 (see section 5.4).

Step 5: Decision: Is remediation being implemented effectively?

Is remediation being implemented in accordance with the requirements of the approval of remediation described in Step 4 or the requirements of a Remediation Order and is it effective? If the Director is not satisfied that remediation is being implemented in accordance with the approval of remediation or Remediation Order or is not being implemented effectively, the Director may determine that security is required at this time and may specify the form, amount and any conditions. Security required in this step shall be calculated using formula 1.

Step 6: Decision: Does the remediation require ongoing management and monitoring of contamination?

If remediation is being implemented effectively and there will be no ongoing management or monitoring at the site, then security shall not be required. If ongoing management and/or monitoring of a site is required due to contamination remaining, financial security, subject to Step 7, shall be considered based on formula 2 (see section 5.5).

Step 7: Decision: Could a significant risk arise at the site and is a covenant unlikely to be effective in ensuring necessary remediation?

Section 48 (4) of the Regulation includes items that shall be considered before financial security is requested. They include:

- the significance of any risks from conditions at the site because a) the site is unremediated or partially remediated, or b) the site requires ongoing management and monitoring of remaining contamination, and
- the effectiveness of a covenant under section 219 of the *Land Title Act* in ensuring that necessary remediation is carried out at the site.

If the risks at a site are significant because remaining contamination requires ongoing management and monitoring, and if a covenant would not likely be effective in ensuring that necessary remediation is carried out, then security shall be required.

4.0 Determination of remediation costs

4.1 The person shall provide an estimate of the costs of remediation that includes, but is not limited to, one-time capital costs and any periodic and recurring costs. A calculation of these costs is required in order to determine the level of security required and shall be submitted to the Director in a remediation feasibility study.

4.2 Remediation cost estimates shall assume that the work will be carried out by a third party contractor.

4.3 If the person is unwilling or unable to generate site remediation cost estimates to the satisfaction of a Director, the Director shall arrange to have a third party do so at the expense of the person or require the person to do so under a Remediation Order.

4.4 The person shall provide all pertinent material and information used to calculate estimated site remediation costs.

4.5 A Director may develop alternate cost estimates for remediation of a site.

4.6 If the cost estimates of a Director and those of the person vary by less than 10 percent, then the lower of the estimates may be used as a basis for determining the amount of security required. If the cost estimates vary by 10 percent or more, then a negotiated agreement shall be sought, but if a negotiated agreement cannot be achieved, the Director's cost shall apply.

5.0 Calculation of the amount of security required

5.1 A Director shall review all estimates of costs of remediation for accuracy, completeness and reasonableness. Such estimates shall include, but not be limited to:

- capital and other one-time costs including their replacement time-frames
- recurring and periodic costs
- planning period of the remediation process
- discount rates used

- time frames, deadlines and plans that will be implemented in order to carry out site remediation.

5.2 The amount of the required security shall be based on the least cost remedial alternative as long as the proposed remediation is acceptable to a Director. If the Director and the person(s) cannot agree on the alternative remediation options or the least cost option, the Director shall make a final determination of the value of the costs and the amount of security required.

5.3 The planning period for calculation purposes in sections 5.4 and 5.5 is limited to 30 years.

5.4 Formula 1: Remediation not progressing as required or no approved remediation

5.4.1 If security is required because remediation acceptable to a Director has not been approved or remediation is not progressing as required, then the amount of the security required will be calculated to include:

- the estimated one-time capital costs to build and install contaminant management and monitoring system(s); and/or
- the estimated recurring and periodic costs to operate and monitor and maintain any management and monitoring systems developed; and/or
- the removal and disposal costs for contaminants that shall be removed in order to remediate the site to acceptable standards.

5.4.2 The above calculation includes the costs that would be required for the Crown or a third party to bring the site into compliance with the terms and conditions of any contaminated sites legal instrument.

5.4.3 The amount of security required shall equal 100% of the one-time capital costs plus the present value of the total management and monitoring costs over the entire planning period specified in the contaminated sites legal instrument.

5.5 Formula 2: Ongoing management and monitoring

If security is required as part of an ongoing management or monitoring system for contamination left onsite in accordance with ministry approved remediation, security shall be calculated based on 100% of the following costs:

- the estimated one-time capital costs to build and install management and monitoring system(s); and
- the estimated recurring and periodic costs to manage, monitor and maintain any systems developed.

5.6 Fluctuations

5.6.1 Present value calculations inherently assume that funds invested will grow with interest over time and that the "costs" or payments per year occur at a standard rate. This is not always the case, for example, where management and monitoring costs change once systems are in place if improvements are made or if security is a letter of credit.

5.6.2 The changing level of security required over time depending on the nature of security payments shall be kept in mind when calculating the amount of security required. (See Appendix B in reference 2 cited in section 11 of this document).

5.7 Effects of Inflation

5.7.1 Where costs of remediation are incurred in future years and these costs are included in the present value of the security required, these future costs shall be adjusted to account for the effects of inflation.

5.7.2 For estimating future one-time capital and recurring costs, the annual inflation rates used shall be drawn from Canada's most recent Consumer Price Index (CPI), or the average of the past 10 years CPI, whichever is lower.

5.7.3 Calculations to inflate future costs on an annual basis shall be based on the following formulas:

$$FACn = ACn * (1 + f)^n$$

$$FOCn = OCn * (1 + f)^n$$

Where:

FACn = future (inflated) recurring costs expended in year n and the initial year is n = 0

FOCn = future (inflated) capital and other one-time costs expended in year n and the initial year n = 0

ACn = annual recurring costs in year n; where the costs in the initial year are not inflated

OCn = capital and other one-time costs in year n

n = a specific year, where n ranges from 0 to the (t - 1)th year

t = number of years in the planning period (no greater than 30 for formula 2)

f = inflation rate as a decimal number where f is always greater than 0 and less than 1

5.8 Calculation of present value

The present value of one-time capital and other one-time items and of recurring and periodic costs over the planning period shall be computed using the following formula:

$$PV = \sum \text{(sum of)} \left[(FACn + FOCn) * (1/(1+r)^{n}) \right]$$

Where:

PV = present value of all costs over the contaminated sites legal instrument period
FACn = the future (inflated) annual management and monitoring costs expended in year n
FOCn = the future (inflated) capital costs expended in year n
r = the discount rate
n = a specific year designated 0, 1, 2, etc. up to a pre-specified final year (t -1)th year
t = number of years covered under the planning process (maximum 30 years under formula 2)

The present value of remediation costs shall be based on capital, management and monitoring expenditures being made throughout the year and not entirely at the end of the year.

5.9 Discount Rate

The discount rate to be used in the present value formula above shall be a rate consistent with the form of security chosen and the time period specified in the contaminated sites legal instrument.

The maximum discount rate used shall be based upon the rate of interest for Government of Canada 30-year bonds, as published in the journal *Bank of Canada Review* or other respected financial reporting publication such as the *Globe and Mail* newspaper.

6.0 Forms of security

6.1 Acceptable forms of financial security are defined in section 1.0 of this Protocol under the definitions of “security” and “financial security”.

6.2 In addition to the specific forms of financial security listed in this definition, there may be situations where a person may wish to post alternative types of financial security such as performance or surety bonds. In these situations, the person shall prepare a written request to a Director outlining the reasons for the request to vary the type of security.

6.3 A Director shall review each request on an individual basis. The arguments posed by the person shall be sufficiently compelling in order for a Director to vary the type of security accepted.

6.4 An analysis of the alternative types of security requested shall be performed either by a Director or an independent third party, at the expense of the person.

7.0 Diminishment of assets

7.1 Subject to section 37 of the Regulation, a person who is required to provide security under a contaminated sites legal instrument shall be required in the legal instrument that he or she shall not, without notifying a Director, offer the site for sale, proceed with bankruptcy proceedings, or knowingly do anything that diminishes or reduces assets that could be used to satisfy the terms and conditions of the contaminated sites legal instrument.

7.2 In the case of a Remediation Order the responsible person must obtain consent from a Director before diminishing or reducing the assets [Act 48 (8)].

8.0 Periodic reviews of security

8.1 A Director shall carry out a review of the security for a site at least every five years and no more than once per year.

8.2 A person providing security for a site shall be required to forward to a Director annually a copy of his or her firm's most recently audited annual financial statements along with a copy of the firm's signed annual report.

8.3 For projects where costs are changing significantly, a Director shall perform a security review more frequently than every five years. The review shall include an analysis of the adjusted projected costs of the project in relation to the actual costs incurred to date, and shall analyse these costs in relation to the current value of the security provided.

8.4 On an annual basis, a Director or the person posting the security may request a review of the amount of security required to be posted. Adjustments may be required or approved by the Director.

8.5 If government bonds or other debt instruments are used as financial security, then the value of these instruments shall be reviewed by a Director at least every three years and their value compared with the level of security required. Adjustments in the value of these debt instruments may be required.

8.6 When issuing a contaminated sites legal instrument, a Director shall include terms and conditions requiring the periodic review of security, to ensure that adequate funds are available for the remediation requirements specified in the instrument.

9.0 Conditions for realizing security

9.1 The conditions that can cause security to be called shall be clearly specified in the contaminated sites legal instrument. These conditions may include but are not limited to the following situations:

- The person for reasons within his or her control misses three successive deadlines in a schedule of requirements provided in a contaminated sites legal instrument.
- After one half of the time allocated to the implementation of the remediation schedule referred to in a contaminated sites legal instrument has elapsed, or after two years, whichever is earlier, the person cannot provide adequate evidence (i.e., work orders, invoices, inspections, etc.) of progress to comply with the conditions of the contaminated sites legal instrument.
- The person has violated a specific contaminated sites legal instrument or any other order or statute in relation to the site.
- The person or the guarantor becomes bankrupt, files a Notice of Intention or files a Proposal under the *Bankruptcy and Insolvency Act.*
- When notice is received of the proposed cancellation or non renewal of a letter of credit or of some other form of security, and an acceptable alternative form of security has not been arranged.

9.2 Security held in a non cash form shall be converted to cash as soon as possible whenever the security becomes impaired.

9.3 Where possible a Director shall give the person at least 30 days notice with supporting rationale of any action to use the security.

9.4 If security has been given in the form of cash, bonds, letter of credit, or similar security, a Director may claim all or part of the security. The security shall be placed in a designated account.

9.5 Where security has been realized and is to be used to complete remediation as specified in a contaminated sites legal instrument, expenditures on remediation of the site shall not be made unless authorized by a Director.

10.0 Administrative procedures for specific types of security

Procedures for administering cash, irrevocable letters of credit, and eligible government bonds are contained in Appendix 2.

11.0 References

1) Grant Thornton, Security Policy Guidance for Contaminated Sites: Findings, Report prepared for the Ministry of Water, Land and Air Protection, May 28, 2003.
2) Grant Thornton, Security Policy Guidance for Contaminated Sites: Decision Matrix, Report prepared for the Ministry of Water, Land and Air Protection, May 28, 2003.

The preceding documents are available through the ministry's contaminated sites web site under the discussion papers and reports heading.

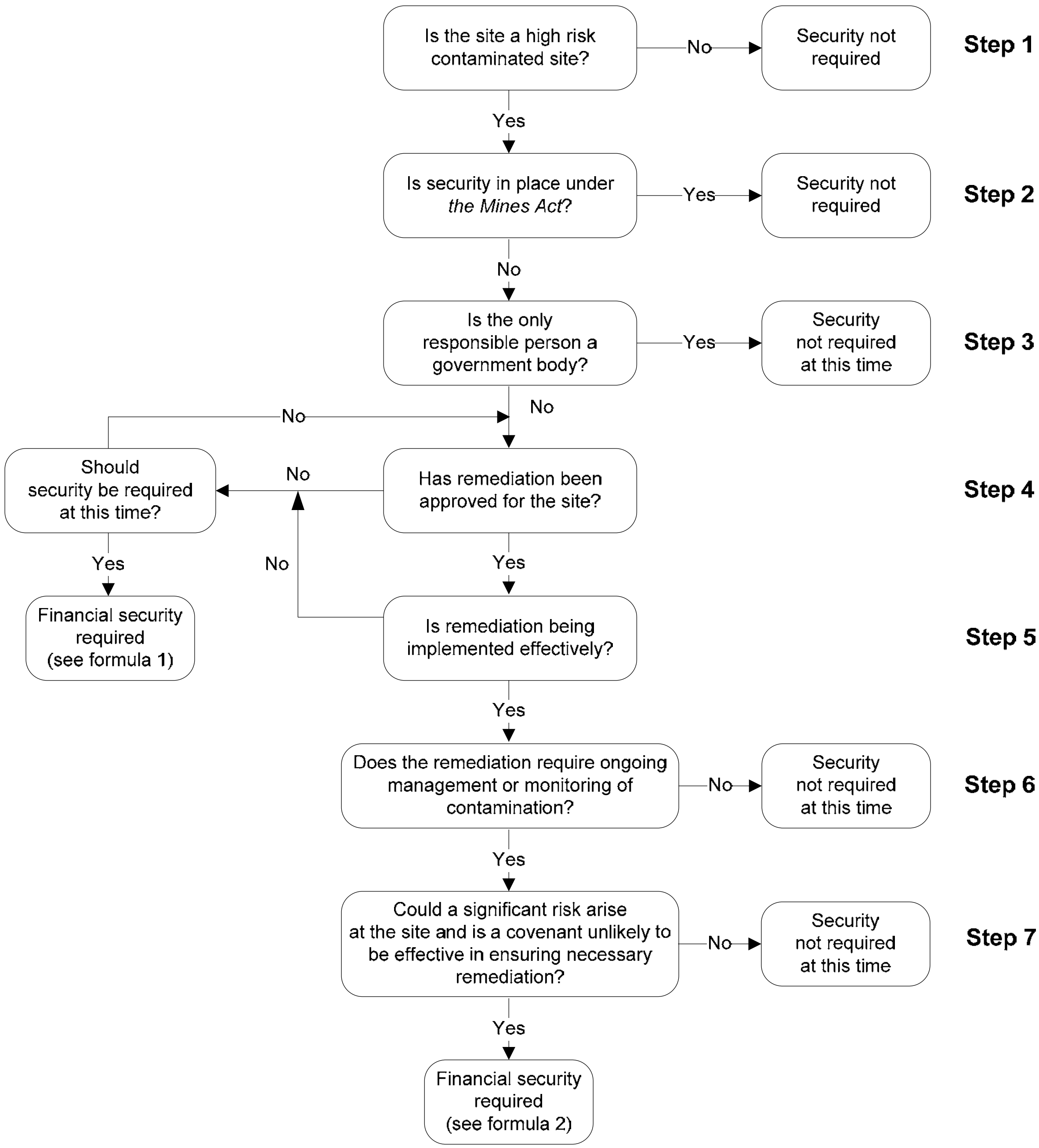

Figure 1. Contaminated sites security decision tree.

Appendix 1.
Legal and Regulatory Authority for Security in *Environmental Management Act* and Contaminated Sites Regulation

The following parts of the Act and Regulation authorize the provision of security for contaminated sites.

Environmental Management Act

48 (2) A Remediation Order may require a [responsible person] to do all or any of the following:

(c) give security, which may include real and personal property, in the amount and form the director specifies.

51 (1) On the request of a responsible person, including a minor contributor, a director may enter into a voluntary remediation agreement in accordance with the regulations, consisting of:

(c) security, which may include real and personal property, in the amount and form, and subject to conditions the director specifies.

53 (3) A director, in accordance with the regulations, may issue a certificate of compliance [to a person] with respect to remediation of a contaminated site if

(d) any security in relation to the management of contamination, which security may include real and personal property in the amount and form and subject to the conditions specified by the director, has been provided and the requirements respecting that security prescribed in the regulations have been met . . .

54 (3) A director may at any time during independent remediation by any person

(d) impose requirements that the director considers are reasonably necessary to achieve remediation.

Contaminated Sites Regulation

47 (3) When issuing an approval in principle under section 53 (1) of the Act, a director may specify conditions for any or all of the following:

(f) any financial security required by the director in accordance with section 48.

48 (4) A director may require financial security if

(a) a significant risk could arise from conditions at a contaminated site because

(i) the site is left in an unremediated or partially remediated state, or

(ii) the site is remediated but requires ongoing management and monitoring because contamination is left at the site, and

(b) a covenant under section 219 of the *Land Title Act* is, in the opinion of the director, unlikely to be an effective means to ensure that necessary remediation is carried out at the site.

48 (5) The financial security required by a director under subsection (4) may be for the purpose of any or all of the following:

(a) ensuring that a responsible person completes remediation or guarantees performance to the satisfaction of the director;

(b) providing funds to further treat, remove or otherwise manage contamination;

(c) complying with the applicable legislation and financial management and operating policies of British Columbia.

Appendix 2.
Administrative Procedures for Specific Types of Financial Security

1.0 Procedures for administering cash

1.1 Certified cheques made out to the Minister of Finance shall be submitted to the Director.

1.2 The cheques shall be deposited into an account in accordance with applicable legislation and relevant government Core Policy and Procedures Manual provisions.

1.3 If financial security is to be built up through payments over time, payments may be based on a per-unit price (e.g. dollars per tonne of hazardous material) or an amortization payment calculated to accumulate to a total amount by a specific time in accordance with section 5.6.2 of this Protocol.

1.4 Applications for refunds of financial security shall be sent to the Director.

1.5 A Director shall maintain records of all deposits of financial security and issue reports regularly as required under government policy. Reports on each account shall include, at minimum, the following:

- payments into and out of each account,
- accrued interest, and
- opening and closing balances.

2.0 Procedures for administering irrevocable letters of credit

2.1 Only irrevocable letters of credit from financial institutions empowered to issue such instruments with business offices in B.C. may be accepted.

2.2 Irrevocable letters of credit shall be retained by the Director.

2.3 An irrevocable letter of credit will normally specify an expiry date.

2.4 Where security is required for a period longer than the expiry date of the irrevocable letter of credit, the letter of credit shall state that it would be renewed automatically.

2.5 An irrevocable letter of credit shall not be renewed if a Director advises the financial institution in writing that renewal is not required.

2.6 If notice of intent not to renew a letter of credit is given by the financial institution, alternative security satisfactory to a Director shall be posted at least 30 days before the letter's expiry date.

2.7 If alternative security is not posted as required in section 2.6 or notice not to renew a letter of credit is given with no alternative security posted, the existing irrevocable letter of credit will be called and the proceeds are to be administered as a cash form of financial security.

2.8 Any contaminated sites legal instrument shall provide that, where non-cash security (e.g. a letter of credit or surety bond) is provided and appropriate arrangements are not made for its renewal or replacement at the time of expiry, then cash security shall be immediately posted in lieu of the non-cash instrument.

2.9 A Director shall maintain records of all irrevocable letters of credit and prepare reports semi-annually, or more frequently, as required under government policy.

2.10 As remediation is undertaken and, at the request of the person, a Director shall notify the financial institution by letter as to the status of the remediation and security requirements; e.g. whether the amount of the irrevocable letter of credit can be reduced, or that the irrevocable letter of credit is to be released. If it is to be released, the original letter of credit and any required supporting documents are to be returned to the financial institution.

2.11 Drawings on letters of credit and reductions in, or release of irrevocable letters of credit shall be authorized by a Director only after 30 days notice is made to the person.

2.12 A person is responsible for all fees and charges associated with the irrevocable letter of credit.

3.0 Procedures for administering the use of eligible government bonds as security

3.1 Bonds are considered debt instruments issued or guaranteed by the Government of Canada (excluding Canada Savings Bonds) or a provincial government and shall be distinguished from surety or performance bonds.

3.2 Bonds used as a security shall have a maturity date that is not more than three years from the date on which they are provided as security.

3.3 Bonds shall be in bearer form or they shall be transferred to the Government of British Columbia.

3.4 Bonds shall be retained by the Director.

3.5 A Director shall report annually or more frequently on bonds he retains for security as required under government policy.

3.6 A Director shall monitor the value of the bonds at least quarterly.

3.7 If the value of the bonds on deposit falls to less than 85 percent of the required security for a site, a Director may require the person to provide additional security.

3.8 A Director may make arrangements with persons who have posted a bond as security, if the bond is maturing or interest is due and payable, to accept a substitute bond as security. If no substitutions are made and a bond matures or interest payments are received, the proceeds shall be deposited and administered as a cash form of financial security.

CANADIAN PROVINCIAL REPORT—MANITOBA

1. Background and History

1.1 Minerals and Mining Sector

There are two main components to the mining industry in Manitoba: metallic minerals and industrial minerals. Metallic minerals produced in Manitoba include: zinc, nickel, copper, gold, and silver. Manitoba also produces cesium, which is considered an industrial mineral. Silver, cobalt, and platinum group metals are by-products of mined metals and other minerals. Other industrial minerals include: dolomite, gypsum, sodium chlorate, dimension stone, lime, crushed rock, sand, and gravel aggregate.

The dominant mining activities in the province include mining, smelting, and refining of base and precious metals, as well as mining and quarrying of industrial metals. There are eight currently producing mines, one operating smelter, and two refineries. There are 11 major producers active in the industrial minerals sector in the province. As in other jurisdictions, the mining industry in Manitoba consists of small to medium private mining companies and large, publically held, multi-national corporations.

1.2 Petroleum Sector

Crude oil extraction is another dominant activity within the province of Manitoba. As of April 2014, there were a total of 40 companies active in oil exploration. There are currently four advanced exploration projects occurring within Manitoba.

There are 39 companies that produce oil in Manitoba. These companies range from small, locally based producers to the large multi-national companies. Manitoba's oil production has seen rapid growth. Production has increased almost five times since 1999, with the current level of production at 48,000 barrels per day. There is no natural gas production in the province.

2. Regulatory Structure

2.1 Statutory Framework

2.2 Minerals and Mining

The Mines and Minerals Act (MMA) of Manitoba came into force on April 1, 1992. The MMA forms the basis for how the provincial government manages its mineral resources and is composed of 19 parts. The most relevant parts of the MMA to mine dismantlement, restoration, and remediation (DR&R) are:

- Part 7 – Mineral Leases
- Part 8 – Quarry Minerals

- Part 14 – Rehabilitation
- Part 15 – Public Safety and Hazardous Lands
- Part 16 - Recording of Instruments

Part 7 of the MMA outlines how metallic mineral leases are established and permitted, and identifies what is required before a mining permit can be issued and before a mine can initiate operation. Industrial mineral leasing requirements are covered under Part 8. Both parts of the MMA dictate that an approved closure plan and security for mine closure be established prior to a lease permit being issued. Details regarding closure requirements are outlined in Part 14. Part 15 provides some guidance regarding abandonment of mine sites. Part 16 addresses how security instruments are documented and recorded in Manitoba.

2.2.1 Petroleum Sector

The Oil and Gas Act (OGA), Continuing Consolidation of the Statutes of **Manitoba** (CCSM) Chapter O34 came into force July 1, 1994. The OGA forms the basis for managing oil and gas resources within the Province of Manitoba. The Act is composed of 23 parts. The most relevant parts of the OGA to this study are:

- Part 4 – Dispositions
- Part 5 - Registration of Transfers and Instruments
- Part 8- Well Licenses
- Part 9 – Oil and Gas Production and Conservation
- Part 12 – Flow Lines and Pipelines
- Part 14 – Performance Security

2.3 Regulatory Framework

2.3.1 Mining Regulations

Mine Closure Regulation 67/99 provides the regulatory basis for security requirements associated with DR&R requirements for mines.

2.3.2 Petroleum Regulations

Drilling Production Regulation 111/94 under the OGA identifies financial assurance requirements for oil and gas facilities including wells, batteries, and flow lines. Within the context of this regulation, a battery is defined as “a facility used to store, process, or dispose of oilfield waste” (Drilling and Production Regulation 111/94, Part 1 – Definitions). Under the Drilling and Production Regulation, the term “performance deposit” is used to denote the form of financial assurance a lessee or permit holder must provide when obtaining either a well license or battery operating permit. In addition to a performance deposit, an initial levy for each well license must be paid into the Abandonment Fund Reserve Account (AFRA). For inactive wells or batteries, the licensee must pay an annual non-refundable levy into the AFRA

2.4 Regulatory Agency Structure

The Department of Mineral Resources (DMR) regulates and manages both mineral and petroleum extraction within the Province of Manitoba. There are four branches within the Department; however, the Mines Branch and the Petroleum Branch are the two entities responsible for regulating mining and petroleum resource activities in the province. The Mines Branch regulates all aspects of mine development from the disposition of mineral rights (permits, claims, and leases) through exploration, development, production, and eventual mine rehabilitation. All non-fuel mineral resources are managed by the Mines Branch. The Petroleum Branch administers all aspects of petroleum-related activities. Within its jurisdiction, the Petroleum Branch regulates exploration, development, production, transportation, and storage of crude oil and natural gas. It is also responsible for administering other regulatory programs including the requirements identified in the Oil and Gas Production Tax Act and the Manitoba Drilling Incentive Program. The Petroleum Branch maintains a comprehensive public database of technical well and reservoir information. It also reports on the province's petroleum geology and hydrocarbon potential to encourage and assist in the exploration and development of Manitoba's oil and gas resources.

3. Financial Assurance

3.1 Forms of Financial Assurance

3.1.1 Mining Sector

The Province of Manitoba allows for both hard and soft forms of financial assurance. Hard forms of financial assurance listed in Table 3.1-1 remain the dominant, traditional form of financial assurance used in Manitoba. However, the use of soft forms of financial assurances, such as a corporate financial test, has increased in popularity in more recent years. Such forms of financial assurance require the corporation to meet a certain credit rating. If the corporation’s rating is reduced by the rating service, financial assurance requirements are re-examined by DMR.

Table 3.1-1 Forms of Financial Assurance Accepted for Mining

Hard Forms	Soft Forms
• Cash or check • Provincial or Canadian bonds; • Guaranteed investment certificate or term deposit certificate • Irrevocable, unconditional letter of credit security or	• Canadian Bond Rating Services, Inc. • Dominion Bond Rating Services, Limited • Moody’s Investor Services, Inc. • Standards and Poor’s Inc. • Senior investment-grade rating service accepted

Table 3.1-1 Forms of Financial Assurance Accepted for Mining

Hard Forms	Soft Forms
guarantee policy • Third-party security • Security interests that arise from assignment of accounts including a pledge of assets • Any other form of security, guarantee, or protection acceptable to the Director • Any combination of the above instruments	to the Director.

The security filed with a closure plan under Section 74 (advanced exploration project), 111 (mine), 188(2) (non-aggregate quarry), or 191 (revised plan) is held in the Mine Rehabilitation Fund. Where, in respect of a project, monies are credited to the Mine Rehabilitation Fund under subsection (1), the Minister of Finance shall deposit the receipts in mine rehabilitation reserve accounts to be established by the Minister of Finance under the Consolidated Fund and maintained in the names of the projects to which the receipts relate.

3.1.2 Petroleum Sector

The forms of financial assurance accepted for the petroleum sector as performance deposits are limited to cash or a term deposit. In accordance with Drilling and Production Regulation 111/94, Section 10(1)(b), the term deposit must be issued by a bank, trust company, or credit union. The term deposit must be assigned to the Manitoba Minister of Finance with a confirmation provided in writing by the organization who issued the term deposit.

3.2 Calculating Financial Assurance Requirements for Mining Sector

Currently, the Mines and Minerals Act regulations do not provide detailed information concerning how to calculate the amount of financial assurance required for a mining operation. However, the DMR provides guidance regarding financial assurance on its website. The website lists the form or financial assurance and indicates when financial assurance is required. The DMR provides a general framework for estimating the costs.

3.2.1 Mining Reclamation Costs Included In Security

The physical areas on which reclamation and rehabilitation costs are targeted are referred to as Accumulation Areas. Individual components of a mining operation that must be accounted for in the calculation of financial assurance include, but are not limited to:

- Tailings ponds, including sedimentation and polishing ponds
- Waste rock piles

- Mining waste piles
- Concentrate and ore stockpiles
- Mine water ponds
- Shaft caps, buildings, and any other safety hazards identified in the Mine Closure Plan.

These costs are provided in the Mine Closure Plan and correspond to the estimated cost of restoration, monitoring, and perpetual care and treatment of Accumulation Areas. The Director of the DMR reviews the estimate of financial assurance provided in the Mine Closure Plan and will either approve the amount provided or may increase or reduce the amount of security required. Factors that could influence the level of financial assurance required include:

- Progress of the rehabilitation work compared to the schedule in the Mine Closure Plan
- Amount of pre-closure rehabilitation work completed when the mine is shut down
- Changes in the nature or cost of work to be done pursuant to the Mine Closure Plan.

In addition, the financial assurance posted for the mining operation may be reviewed when a change to the Mining Plan is required. The first installment of financial assurance must be provided within 60 days following the approval of the Mine Closure Plan.

3.2.2 Corporate Financial Test

In order to qualify for using a soft form of security as financial assurance for up to the entire life of the mine, a mine owner/operator (proponent) must demonstrate that it meets one of the following ratings listed in Table 3.2-1.

Table 3.2-1 Corporate Financial Test for Demonstrating Financial Assurance for Entire Mine Life

Approved Credit Rating Service[1]	Minimum Rating		
	Rating	Description	Scale Reference
Dominion Bond Rating Service Limited	A (low)	**Good credit quality** The capacity for the payment of financial obligations is substantial, but of lesser credit quality than AA. May be vulnerable to future events, but qualifying negative factors are considered manageable.	Long-Term Obligations Rating Scale
Moody's Investor Services Inc.	A3	Upper-medium grade and are subject to low credit risk. Modifier 3 indicates a ranking in the lower end of that generic rating category.	Long-Term Rating Scale

Table 3.2-1 Corporate Financial Test for Demonstrating Financial Assurance for Entire Mine Life

Approved Credit Rating Service[1]	Minimum Rating		
	Rating	**Description**	**Scale Reference**
Standard & Poor's Inc. (S&P)	A-	**Investment Grade** Obliger has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. Minus (-) sign shows relative standing within the major rating categories.	Long-Term Issuer Credit Ratings

Notes:

1 Mine Closure Guidelines Financial Assurance, written in 2001, cites the Canadian Bond Rating Service, Inc. as an approved credit rating service; however, this rating service company was purchased by S&P, and the Canadian Bond Rating Service Ratings have been harmonized with the S&P ratings.

When a proponent elects to use a corporate financial test to demonstrate financial assurance, it must provide the name of the rating service used, along with confirmation from the service that it meets the required rating. The proponent must also identify the form and amount of financial assurance it will provide if it ceases to meet the rating established under the corporate financial test. If the rating service used to demonstrate financial assurance downgrades or puts the proponent on credit watch, the proponent must notify the Director of the DMR within 7 days of issuance of the rating downgrade or credit watch. The proponent must notify the Director of the DMR within 30 days if any other matter arises that may materially affect the proponent's financial assurance status or the life of the mine. The proponent must also provide the Director of the DMR with financial assurance in the form and amount identified in the Mine Closure Plan within 30 days of no longer being able to meet the corporate financial test.

In order to qualify for using a soft form of security as financial assurance for up to the first half of a mine's life, a proponent must demonstrate that it meets one of the following ratings listed in Table 3.2-2.

Table 1.2-2 Corporate Financial Test for Demonstrating Financial Assurance for First Half of Mine Life

Approved Credit Rating Service[1]	Minimum Rating		
	Rating	**Description**	**Scale Reference**
Dominion Bond Rating Service Limited	BBB (low)	**Adequate credit quality** The capacity for the payment of financial obligations is considered acceptable. May be vulnerable to future events.	Long-Term Obligations Rating Scale
Moody's Investor Services Inc.	Baa3	Medium-grade and subject to moderate credit risk, as such may possess certain speculative characteristics. Modifier 3 indicates a ranking in the lower end of that generic rating category.	Long-Term Rating Scale

Table 1.2-2 Corporate Financial Test for Demonstrating Financial Assurance for First Half of Mine Life

Approved Credit Rating Service[1]	Minimum Rating		
	Rating	Description	Scale Reference
S&P	BBB-1	Considered lowest investment grade by market participants	Long-Term Issuer Credit Ratings

Notes:
1 Mine Closure Guidelines Financial Assurance, written in 2001, cites the Canadian Bond Rating Service, Inc. as an approved credit rating service; however, this rating service company was purchased by S&P. The Canadian Bond Rating Service Ratings have been harmonized with the S&P ratings.

The proponent is held to the same notification requirements when it seeks to use the corporate financial test to demonstrate financial assurance during the first half of the mine's life as those seeking the same for the entire life of mine. However, if the proponent's rating is downgraded or no longer meets the corporate financial test criteria, it has 180 days from expiration of the first half of the mine life to provide the form and amount of financial assurance identified in the Mine Closure Plan.

3.2.3 Recommended Guidance for Paying Mining Securities

Guidance has been developed by a joint committee of federal-provincial-territorial government and mining industry representatives suggesting that a percentage of total reclamation cost be deposited as financial assurance each year based on the total expected life of the mine. The funds must be accrued such that 100 percent of the total amount required to reclaim the mine site is deposited 1 year prior to end of the mine's expected life or by Year 14 for mines expected to operate beyond 15 years (Government of Manitoba 2014). The Director of the DMR must approve the final amount of financial assurance that a mine is required to provide. The schedule provided in Table 3.2-3 has not been codified into Minerals and Mining Act regulation.

Table 3.2-3 Recommended Schedule of Annual Security Provided

Expected Mine Life (years)	Annual Amount Recommend for Deposit by Mine Year per $1 (CDN) of Financial Assurance														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	1.00														
2	1.00	-													
3	.500	.500	-												
4	.111	.333	.556	-											
5	.063	.187	.313	.437	-										
6	-	.063	.187	.313	.437	-									
7	-	.030	.123	.180	.300	.367	-								
8	-	.028	.030	.102	.173	.300	.367	-							
9	-	.020	.028	.040	.092	.153	.300	.367	-						
10	-	-	.020	.055	.095	.163	.177	.225	.265	-					
11	-	-	.016	.020	.050	.090	.157	.177	.225	.265	-				
12	-	-	.012	.016	.020	.050	.088	.147	.177	.225	.265	-			

Table 3.2-3 Recommended Schedule of Annual Security Provided

Expected Mine Life (years)	Annual Amount Recommend for Deposit by Mine Year per $1 (CDN) of Financial Assurance														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
13	-	-	.010	.030	.050	.063	.080	.100	.130	.150	.180	.207	-		
14	-	-	-	.010	.030	.050	.063	.080	.100	.130	.150	.180	.207	-	
15 or more	-	-	-	.010	.010	.020	.050	.063	.080	.100	.130	.150	.180	.207	-

3.3 Petroleum Sector Financial Assurance Calculation

3.3.1 Performance Deposits

The holder of a well license or battery operating permit must provide $ 7,500 CDN for each well and battery up to a maximum of:

- $15,000 CDN
- $30,000 CDN where, in the opinion of the Director, the net revenue from the wells or batteries to which the performance deposit is applied is, over the 6 months preceding the day on which the performance deposit is determined, less than the cost of abandoning the wells or batteries
- $60,000 CDN where, in the opinion of the Director, the net revenue from the wells or batteries to which the performance deposit is applied is, over the 12 months preceding the day on which the performance deposit is determined, less than the cost of abandoning the wells or batteries.

The Director of DMR may re-determine the amount of performance deposit required if circumstances change since the proponent posted the performance deposit. A performance deposit paid at one of two higher amounts can be reduced to $15,000 CDN if the Director of the DMR has deemed that special circumstances exist. With prior approval from the Director of the DMR, a letter of credit may be submitted by the proponent for the portion of performance deposit in excess of $15,000 CDN.

3.3.2 Abandonment Fund Reserve Account Levies

As indicated above, a well license application or transfer of a well license must be accompanied by a levy, which is deposited into AFRA. For an initial well license, the levy is $250 CDN per well license and is $50 CDN per well license transferred. The levy required to accompany a battery operating permit is $250 CDN.

For inactive wells or batteries, an annual, non-refundable levy must be paid by the well license or battery operating permit holder. Inactive wells are categorized into one of three classes based on how long the well has not been operated (Table 3.3-1). A fourth class is used to designate inactive batteries. Annual levies must be paid by July 31; if the levy is not paid by that date, penalties begin to accrue. For late levies paid before October 31, a 25 percent penalty is charged. If the late levy payment is received after October 31, a 50 percent penalty is incurred.

Table 3.3-1 Levies Required for Inactive Wells and Batteries

Class	Period of Inactivity (Class Description)	Annual Levy Amount (Canadian Dollar per Well or Battery)
1	Fewer than 5 consecutive years	$150
2	Between 5 and 10 consecutive years	$500
3	More than10 consecutive years	$1,000
4	Per Inactive Battery	$500

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CANADIAN PROVINCIAL REPORT—NEWFOUNDLAND AND LABRADOR

1. Background and History

1.1 Mineral Resources

Mining is one of the Province of Newfoundland and Labrador's largest and oldest industries and a major contributor to the economy of the province, especially in rural areas. The province has a large and diversified minerals industry that provides a wide variety of commodities to the world market. The latest forecast is that the total gross value of mineral shipments will be approximately $3.8 billion Canadian dollars (CDN) for 2014, which is up slightly from the estimated 2013 value of nearly $3.7 billion CDN (Department of Natural Resources, Mines Branch 2014). Direct employment in the minerals industry hit an all-time record high for 2013 at 11,250 person years (Department of Natural Resources, Mines Branch 2014).

A total of 14 mineral commodities are produced or mined in the province. Seven metal mines currently produce iron ore, nickel, copper, zinc, cobalt, and gold, with iron, nickel, and copper being the most significant. Other operations mine pyrophyllite, limestone, and dolomite.

1.2 Hydrocarbon Resources

The Province of Newfoundland and Labrador has an abundance of oil and natural gas. Three facilities are currently producing oil in the province’s offshore region at the Hibernia, Terra Nova, and White Rose oil developments. In January 2009, the combined projects achieved a major milestone, reaching one billion barrels of oil produced. In addition to these projects, the province recently reached agreements for expansion of the original Hibernia and White Rose developments and a new project, Hebron – estimated to contain 400 to 700 million barrels of recoverable oil, is progressing with first oil forecast between 2016 and 2018.

The Province of Newfoundland and Labrador produces about 270,000 barrels of crude oil per day, representing 10 percent of Canada’s total crude oil production. The Canada-Newfoundland and Labrador Offshore Petroleum Board estimates oil reserves for each of the major producing discoveries at:

- Hibernia: 1.24 billion barrels discovered
- Terra Nova: 419 million barrels discovered
- White Rose: 283 million barrels discovered; North Amethyst, a White Rose satellite expansion project which began producing in 2010, contains an additional 68 million barrels of oil.

The province also continues to see vibrant oil and gas exploration. The prolific Jeanne d’Arc Basin continues to enjoy active exploration programs by existing and new participants in the province’s oil and gas sector. In addition, in recent years, more companies are exploring the deeper waters of the Orphan Basin, Flemish Pass Basin, and the Laurentian Basin.

The Newfoundland-Labrador Department of Natural Resources is conducting independent reviews of hydraulic fracturing (Newfoundland-Labrador Department of Natural Resources 2014). The study in Newfoundland-Labrador follows an announcement on November 4, 2013 stating that the Minister of Natural Resources would not accept any applications for onshore and onshore to offshore petroleum exploration using hydraulic fracturing (Newfoundland-Labrador Department of Natural Resources 2014).

Onshore and offshore western Newfoundland also holds promise with a number of finds onshore, excellent resource potential offshore, and new seismic and drilling programs in both areas.

2. Regulatory Structure

2.1 Governmental Agencies

The Government of Newfoundland and Labrador manages both mineral and onshore petroleum resources under the auspices of the Department of Natural Resources. Within the Department, there are several branches and divisions responsible for managing the various natural resources within this province.

The Nunatsiavut Government is an Inuit regional government (part of Newfoundland and Labrador), and has authority over many central governance areas. These areas include health, education, culture and language, justice, and community matters. The Nunatsiavut Government has the authority to make laws as well.

The Government of Canada has jurisdiction over mining on Crown lands and over offshore oil and gas activities.

2.1.1 Mining Sector

The Mines Branch is the regulatory agency responsible for mining and minerals. It has three divisions: Geological Survey Division, Mineral Development Division, and the Mineral Lands Division. The Geological Survey Division is responsible for the collection, storage, and publication of geoscience data, providing advice concerning exploration potential of the province and providing outreach support among other duties. The Mineral Lands Division is responsible for the issuance and administration of mineral claims, monitoring exploration activities, and issuance of quarry permits and leases. The Mineral Development Division is responsible for approvals for the development and operation of mines, monitoring and analysis of the mining industry, development of mineral policy, management of incentive programs for exploration and development, and for the rehabilitation of hazards associated with abandoned mines (Mineral Development

Division 2014). This division is responsible for conducing engineering analyses, mineral industry analyses, and the administration of the Mining Incentives Program as well.

2.1.2 Petroleum Sector

The Petroleum Branch is responsible for managing onshore petroleum resources. Offshore petroleum resources are managed jointly by the federal and provincial governments through the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB). The C-NLOPB manages the regulatory regime established by the Atlantic Accord in 1985 and the subsequent implementation legislation.

2.1.3 Nunatsiavut Government

The Nunatsiavut Government Department of Lands and Natural Resources is responsible for all matters related to the protection, use, and development of renewable and non-renewable resources in Nunatsiavut. The department is organized into four divisions:

- Lands Division
- Non-Renewable Resources Division
- Renewable Resources Division
- Environment Division.

The Nunatsiavut Government Department of Lands and Natural Resources' mandate is to ensure the sustainable management of Nunatsiavut land and natural resources while maximizing benefits from the development of these resources for Inuit.

The Lands Division is responsible for managing use and access to Labrador Inuit Lands, which are defined within the Labrador Inuit Land Claims Agreement. Within Nunatsiavut, Labrador Inuit own approximately 15,800 square kilometres of land, with 3,950 square kilometres of these lands being further defined as Specified Material Land. This means that Labrador Inuit have the exclusive right to ownership of quarry materials and a 25 percent ownership interest in subsurface resources in this area.

2.2 Statutory Framework

2.2.1 Mining Sector

Mining is regulated under several statutes issued by the Department of Natural Resources within the Government of Newfoundland and Labrador. These statutes include:

- Mineral Act (RSNL 1990, Chapter M-12)
- Mineral Holdings Impost Act (RSNL1990 Chapter M-14)

- Mining Act (SNL1999 Chapter M-15.1)
- Quarry Materials Act, 1998 (SNL1998 Chapter Q-1.1)
- Undeveloped Mineral Areas Act (RSNL1990 Chapter U – 2),

Mineral resources are governed by the Nunatsiavut Government under the following statutes as well:

- Labrador Inuit Land Claims Agreement Act (SNL 2004, Chapter L-3.1)
- The Labrador Inuit Lands Act (IL 2005-14)

2.2.2 Petroleum Sector

Petroleum resources are regulated under several statutes issued by the Newfoundland-Labrador Department of Natural Resources. These statutes include:

- Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act (RSNL 1990 Chapter C-2)
- Petroleum and Natural Gas Act (RSNL 1990 Chapter P-10)

2.3 Regulatory Framework

Several regulations have been promulgated under each of these statutes. These individual regulations describe in detail how the mineral and petroleum resources will be managed from the early phases of exploration and prospecting to the end of field life of a mine or petroleum site.

2.3.1 Mining Sector

The regulations listed in Table 2.3-1 have been promulgated from the mineral and mining statutes described above.

Table 2.3-1 Regulations Promulgated under Mining Statutes

Statute	Related Regulations
Minerals Act (Chapter M-12)	Mineral Regulations (11142/96)
Mineral Holding Impost Act (Chapter M-14)	Mineral Holdings Impost Regulations (1124/96)
Mining Act (Chapter M-15.1)	Mining Regulations (42/00) Small Scale Operations Regulations (41/00)
Quarry Materials Act (Chapter Q-1.1)	The Quarry Materials Regulations (804/96)

Table 2.3-1 Regulations Promulgated under Mining Statutes

Statute	Related Regulations
Undeveloped Mineral Areas Act (Chapter U-2)	Undeveloped Mineral Areas Order Regulation (32/97)
Labrador Inuit Land Claims Agreement Act (Chapter L-3.1) and Labrador Inuit Lands Act (IL 2005-14)	Newfoundland And Labrador Regulation 39/07 Mineral Exploration Standards Regulations

2.3.2 Petroleum Sector

The regulations promulgated in support of the petroleum resource statutes described above are listed in Table 2.3-2.

Table 2.3-2 Regulations Promulgated Under Petroleum Statutes

Statute	Related Regulations
Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act	• Canada-Newfoundland and Labrador Oil and Gas Spills and Debris Liability Newfoundland and Labrador Regulations • Offshore Certificate of Fitness Newfoundland and Labrador Regulations • Offshore Area Oil and Gas Operations Regulations • Offshore Area Petroleum Geophysical Operations Newfoundland and Labrador Regulations • Offshore Area Registration Regulations • Offshore Petroleum Drilling and Production Newfoundland and Labrador Regulations, 2009
Petroleum and Natural Gas Act	• Petroleum Regulations • Petroleum Drilling Regulations • Oil Royalty Regulations • Royalty Regulations, 2003

3. Securities

Some form of financial assurance as determined by the Minister of Natural Resources is required for rehabilitation and long-term monitoring costs up front as part of the approval process for both the mining and petroleum sectors. Financial assurance requirements for each of these sectors are described below.

3.1 Security/Financial Assurance Requirements

3.1.1 Mining Sector

Under Section 10(2) of the Mining Act (Chapter M15.1), the mine lease must provide a copy of a statement from a qualified person in its Rehabilitation and Closure Plan that the estimated costs for completing the work presented in the plan are reasonable. The amount of financial assurance required can be reduced in accordance with this statute, if the Minister of Natural Resources determines that the remaining cost to complete the rehabilitation and closure work is lower than the remaining security. The requirement to provide an estimate of financial assurance required to complete rehabilitation and closure of the mine is reiterated in the General Mining Regulations under the Mining Act (42/00), Section 8(1), which indicates the cost estimate must be included in both the Development Plan and the Rehabilitation and Closure Plan. Section 8(2) of the regulation stipulates that the rehabilitation and closure cost estimate must include costs for ongoing monitoring and site maintenance.

Under Newfoundland and Labrador Regulation 39/07 Mineral Exploration Standards Regulations under the Labrador Inuit Land Claims Agreement Act (O.C. 2007-153), Section 11 identifies the reclamation and closure requirements for exploration sites on Inuit Lands. The regulation stipulates that the Reclamation and Closure Plan must be submitted to the Nunatsiavut Government Department of Lands and Natural Resources for approval. The plan must include an estimate of the number of years exploration will occur, as well as describing details associated with progressive reclamation of the site. Section 11.4 details the information that must be included in the plan. Section 12 of the regulation enumerates the financial security requirements associated with the Reclamation and Closure Plan. While the regulation does not provide a set amount of financial security required, Section 12.2 identifies the types of work that must be included when calculating the total cost of reclamation and closure.

3.1.2 Petroleum Sector

3.1.2.1 Onshore

The Petroleum Drilling Regulations under the Petroleum and Natural Gas Act identify the financial assurance and well abandonment requirements for onshore oil and gas wells. As a condition of approval for a drilling program, Section 14(1)(a) of the Drilling Regulations requires a proponent to provide a performance bond in the form and amount satisfactory to the Minister of Natural Resources requiring the surety named in the bond to terminate the well and leave the drill site in a satisfactory condition in the event of the failure of the operator to comply with these regulations. Section 14(1)(b) of the Petroleum Drilling Regulations requires that the proponent also provide evidence that it is able to meet any financial liability it may incur as a result of drilling a well. Section 117 of the Petroleum Drilling Regulations identifies the site restoration requirement the proponent must meet to abandon or terminate a well. Well abandonment requirements are enumerated in Sections 126 through 130 of the Petroleum Drilling Regulations. Well suspension requirements are listed in Sections 131 through 132 of the Petroleum Drilling Regulations.

3.1.2.2 Offshore

According to C-NLOPB guidelines, an operator involved with the abandonment of wells and decommissioning of a production installation must provide evidence of financial responsibility to carry out these activities. Evidence of financial responsibility must be presented in a development plan, which must be submitted to the C-NLOPB for approval. Within the development plan, the operator must present a decommissioning and abandonment program regarding the abandonment of the well(s) or production facility. The decommissioning and abandonment program must be based on the assumption that all production installations shall be designed and installed to facilitate their entire removal, regardless of whether such removal will actually occur.

3.2 Calculation of Financial Assurance

3.2.1 Mining Sector

The Government of Newfoundland and Labrador does provide detailed guidance concerning the manner in which rehabilitation and closure costs are to be determined. The documents Guidelines to the Mining Act and the Guidebook to Exploration, Development and Mining in Newfoundland and Labrador provide guidelines regarding the type of work that must be completed for mine closure and reclamation.

3.2.2 Petroleum Sector

3.2.2.1 Onshore

According the Guideline Petroleum Drilling Regulations, the amount of the security is determined by the Department of Natural Resources based on the scale and impact of the proposed operations and an estimate of the cost to complete operations, which could include reporting and data submission requirements at any time should the operator fail to do so (Government of Newfoundland and Labrador 2007b).

Satisfying the requirements of Section 14 of the Petroleum Drilling Regulations does not in any way reduce the operator’s financial liability in the case of a blowout, environmental incident, or failure to properly terminate the well. Event-driven environmental liabilities are addressed separately. For publicly held companies, the previous year’s annual report should be submitted to confirm that there are adequate finances available to cover the potential liability incurred these types of incidents. A statement attesting to its financial health from a recognized accounting firm may be required by private operators that are not publically held (Government of Newfoundland and Labrador 2007b).

In addition to posting a security, an operator must carry insurance to ensure it can meet financial liability that may be incurred as a result of carrying out a drilling program. The operator must provide proof of this General Liability and Operator’s Extra Expense insurance for the well. The latter form of insurance normally includes: Control of Well; Re-drilling/Extra Expense; Seepage and Pollution, Cleanup, and Containment;

Care, Custody, and Control; Deliberate Well Firing; Extended Re-drilling and Restoration Cost; Evacuation Expenses; Joint Venture Contingency Liability; Making Well Safe; Removal of Wreckage and/or Debris; Turnkey Wells; Underground Control of Well; and Unlimited Re-drill. In the case of conventional rotary rig drilling, the Operator's Extra Expense policy is required to have a value of $10 million (Government of Newfoundland and Labrador 2007b).

3.2.2.2 Offshore

Costs and proof of financial responsibility for offshore well abandonment and decommissioning of oil and gas facilities are calculated on a case-by-case basis between the C-NLOPB and the operator. Evidence of this financial responsibility must be provided 6 months prior to commencement of production per Section 138 of the Canada-Newfoundland Atlantic Accord Implementation Act. The Guidelines Respecting Financial Responsibility Requirements for Work of Activity in The Newfoundland and Nova Scotia Offshore Areas indicates that the following should be included when developing an estimate of the amount of financial security required for offshore wells and facilities:

- Projected cost associated with the abandonment of the wells and the decommissioning of the production installation
- Manner and form in which the operator will ensure, on behalf of the interest owner, that the abandonment/decommissioning costs will be paid
- Manner, form, and associated costs in which the decommissioned production installation will be maintained (in the event that entire removal is not required)
- Manner and form in which any residual liability will be dealt with by the operator and interest owner, in the event any subsequent claims arise after such abandonment/decommissioning occurs, with respect to damages attributable to the operator's work or activity
- Other information that the C-NLOPB may consider necessary.

3.3 Forms of Security/ Financial Assurance Accepted

3.3.1 Mining Sector

Under Section 10(3) of the Mining Act (Chapter M15.1), the financial assurance required as part of a rehabilitation and closure plan shall be in a form acceptable to the Minister of Natural Resources, including:

- Cash
- Letter of credit from a bank named in Schedule I of the Bank Act (Canada)
- Bond

- Annual contribution to a financial assurance fund established for the project
- Another form of security acceptable to the Minister and the amount specified in the rehabilitation and closure plan, or an amendment to it, shall be acceptable to the Minister.

The Nunatsiavut Government accepts financial securities in the form of cash or check for exploration activities on its lands. A security furnished to the Nunatsiavut Government must be furnished as part of the land use permit issued to a lease and is separate from the security that must be furnished as part of a permit issued by the Government of Newfoundland-Labrador Department of Natural Resources.

3.3.2 Petroleum Securities

The Petroleum Branch accepts either a certified check or an irrevocable letter of credit for payment of a security required prior to approval of an onshore drilling program. In accordance with Section 168(1) of the Canada-Newfoundland Atlantic Accord Implementation Act, the C-NLOPB accepts a letter of credit, guarantee or indemnity bond, or in any other form and amount satisfactory to it.

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CANADIAN PROVINCIAL REPORT—NOVA SCOTIA

1. Background and History

1.1 Mineral Resources

The Province of Nova Scotia has been mined for more than 300 years, resulting in Nova Scotia having produced 20 different mineral products for domestic and foreign use. The Mining Association of Nova Scotia reports that mining provides 5,500 jobs, mostly in rural areas, and contributes some $420 million to the province's economy each year.

Aggregates are the leading mineral produced in Nova Scotia. Gypsum has been mined for more than 100 years, and the province is home to the world′s largest open pit gypsum mine. Nova Scotia's aggregate operations produce approximately 9 million tonnes per year for domestic consumption and approximately 4 million tonnes per year for export. Nova Scotia is known for the quality and size of its gypsum deposits. The province produces approximately 80 percent of the total Canadian gypsum production, and 6 percent of world gypsum production (Nova Scotia Geosciences and Mines Branch 2014). Production has declined by 75 percent compared to 2006 levels. Many of the gypsum mines in Nova Scotia have either shut down or been placed in care and maintenance status indefinitely.

More than 1 million ounces of gold have been produced in Nova Scotia since the first gold mines began operating in 1861. There have been at least three separate gold rushes in Nova Scotia, with gold having been officially discovered in the province as early as 1860 with speculation that gold may have been sighted as early as 1578 when explorer Sir Humphrey Gilbert was given a patent to search for gold and silver in the new world (Bates 1987). Today, the province produces coal, gypsum, aggregate, and salt. Metals produced in significant quantities in Nova Scotia include iron, copper, zinc, lead, tin, and antimony.

Nova Scotia has a thriving salt mining industry, producing about 1 million tonnes of rock salt per year, which is used for de-icing and food-grade products.

Mining of Nova Scotia's coal deposits goes back to the early 1700s, when the French were extracting coal from the exposed cliff face. Coal production levels have dropped significantly over the last decade following closure of the federally owned Devco mines. There is continued interest in developing future underground resources in Cape Breton. Recent coal production has occurred at several surface ′reclamation mining′ projects, where previously mined deposits are being ′re-mined′ and the impacted lands reclaimed to modern environmental standards. Annual coal production in the province is about 500,000 tonnes.

1.2 Hydrocarbon Resources

Nova Scotia, which sits in the Maritimes Basin of Atlantic Canada, is composed of continental and marine sediment that extends over 155,000 square kilometres of the Atlantic Region (Government of Nova Scotia 2013f). Nova Scotia has conventional and non-conventional oil and gas resources, which occur both on and off shore. Conventional petroleum exploration activity is focused on two key rock units that have demonstrated the presence of oil and gas. Oil seeps have been discovered along the shores of the province, which has led to a number of wells being drilled and small quantities of hydrocarbons being discovered. In addition to the potential for conventional oil and gas, coalbed methane (natural gas from coal) from the extensive onshore coal seams in the northern mainland and Cape Breton is being actively pursued.

For more than 135 years, onshore oil and gas exploration has occurred, with the oil wells drilled in Cape Breton in the 1880s being a part of this history. Since 1869, there have been 133 wells drilled throughout the province; however, these wells have produced a limited amount of oil and gas. Currently, there are 10 exploration and production agreements in place between Nova Scotia and oil and gas companies, which are working towards discovery of additional onshore hydrocarbon resources. Recently, Nova Scotia began shifting its focus from crude oil to its abundant natural, shale, and coal gas resources.

Offshore hydrocarbon exploration began in the Scotian Shelf near Sable Island in 1959 with a major gas discovery being found off that island in 1979. This was followed in 1996 by exploration drilling in six gas fields offshore of Sable Island. To date, there have been 209 wells drilled, with 23 wells being considered significant and eight wells being deemed commercially viable. The Nova Scotia Play Fairway analysis estimates that 120 trillion cubic feet of gas and 8 billion barrels of oil exist off its coast. These offshore hydrocarbon resources exist in both deep and shallow water on the continental shelf with small-scale traps containing both oil and gas occurring in shallow water. According to the Play Fairway analysis, the deep-water slope off the coast of Nova Scotia shares the same geological attributes as other successful hydrocarbon-producing regions along the Atlantic Ocean, such as Brazil and the Gulf of Mexico. The geological attributes of these deep water resources include large, sand-rich delta systems; multiple source rocks; and a mobile salt substrate.

2. Regulatory Structure

This section provides an overview of the governmental agencies involved with regulating the mining and petroleum sectors, as well as providing a summary of statutory basis for financial assurance requirements for these two resource sectors. The regulations promulgated under the relevant statutes are described as well. This report only addresses resources under provincial jurisdiction. For resources regulated under federal, Canadian jurisdiction, please refer to the federal report.

2.1 Governmental Agencies

2.1.1 Mining Sector

The mining sector is regulated by both the Nova Scotia Department of Natural Resources and the Department of Environment. The Geosciences and Mines Branch, which is within the Department of Natural Resources, is responsible for implementing policies and programs dealing with the exploration, development, management, and efficient use of mineral resources. The Branch consists of two divisions:

- Geological Services and
- Mineral Management

The Minerals Management Division is responsible for implementing policies and programs dealing with the exploration, development, management, and efficient use of mineral resources, and provides a mineral rights tenure system that establishes legal rights to minerals for exploration and development. The Geological Services Division promotes scientific understanding of the geology of Nova Scotia for use by government, industry, and the public. The Branch promotes the concepts of environmental responsibility and sustainable development, stewardship of the mineral resource sector, and integrated resource planning (Nova Scotia Geoscience and Mines Branch 2014).

The Department of Environment conducts environmental assessments of mine facilities that extract or process metallic and non-metallic minerals including coal, peat, peat moss, gypsum, limestone, bituminous shale, oil shale, and quarriable minerals (such as stone, sand, soil, and gravel). A reclamation plan is developed as part of the environmental assessment and subsequent industrial approval processes. The reclamation plan is then used to determine the value of the reclamation bond that the mine operator is required to post. The reclamation plan is reviewed by the Department of Natural Resources, Department of Environment, and the Community Liaison Committee. A more detailed discussion regarding reclamation bonding within the mining sector is provided in Section 3.

2.1.2 Hydrocarbon Sector

Onshore and offshore hydrocarbon resources are regulated by different agencies within the Department of Energy. Onshore oil and gas activities are regulated by the Petroleum Resources Branch. Offshore oil and gas activities are regulated by the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB). The Board is an independent joint agency of the Governments of Canada and Nova Scotia responsible for the regulation of petroleum activities offshore Nova Scotia.

2.1.2.1 Onshore

There are no freehold petroleum rights in Nova Scotia, which means that all petroleum in or under Nova Scotia lands belongs to the Crown. The Department of Energy’s Petroleum Resource Branch is responsible for the administration of legislation for exploration and development of onshore and offshore petroleum resources and for establishing related policies and regulations. Rights are issued either as exploration or production agreements, each with different periods of tenure. Coalbed methane rights are issued separately with a different tenure period and applicable royalty. The Department of Energy and Department of Environment are currently conducting an independent review of the potential impacts of hydraulic fracturing. Until the review has been completed, Department of Energy will not be issuing permits for shale gas to ensure that the environmental impacts and possible remediation requirements associated with hydraulic fracturing are considered. The studies predominantly focus on water, but include an examination of other potential environmental issues (Nova Scotia Department of Environment 2014):

- Effects on groundwater
- Use and effects on surface water
- Impacts on land, such as potential soil contamination
- Waste management, including surface ponds of produced waters
- Management of additives in hydraulic fracturing fluids
- Site restoration
- Financial security/insurance.

2.1.2.2 Offshore

The CNSOPB, established in 1990 pursuant to the Canada-Nova Scotia Offshore Petroleum Accord Implementation Act (Accord Acts) is the independent joint agency of the Governments of Canada and Nova Scotia responsible for the regulation of petroleum activities in the Nova Scotia Offshore Area. The Board is responsible for the health and safety of offshore workers, as well as for the protection of the environment during offshore activities. It is responsible for the management and conservation of offshore petroleum resources as well. The CNSOPB is also responsible for issuance of licenses for offshore exploration. Offshore resources evaluations, and the collection and distribution of data, are also under the CNSOPB's purview.

2.2 Statutory and Regulatory Framework

2.3 Mining Sector

The Mineral Resource Act and Environment Act form the statutory basis for financial liability requirements for mining activities in Nova Scotia. Each of these statutes has several implementing regulations associated with it. The primary regulation promulgated under the Mineral Resources Act affecting mine dismantlement, reclamation, and remediation (DR&R) activities, including financial assurance requirements, is the Mineral Resources Regulation (2004-435). The Environment Act has DR&R security provisions as well.

2.4 Hydrocarbon Sector

2.4.1 Onshore Petroleum

For onshore petroleum land tenure in Nova Scotia, all activities fall under the provincial Petroleum Resources Act and the Energy Resources Act. Under the Petroleum Resources Act, there are several regulations including: the Petroleum Resources Regulations, Onshore Petroleum Geophysical Exploration Regulations, and the Onshore Petroleum Drilling Regulations.

2.4.2 Offshore Petroleum

The Canada-Nova Scotia Offshore Petroleum Resources Accord and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act (OAA), a federal statute, forms the statutory basis for an agreement between the Government of Canada and the Government of Nova Scotia on offshore petroleum resource management and revenue sharing.

The Nova Scotia Offshore Petroleum Drilling and Production Regulations require an operator to provide evidence of financial responsibility before drilling or re-entering a well. This evidence must demonstrate that the operator has the ability to properly accomplish and terminate the work with regard for the environmental, safety, and other relevant concerns. The evidence provided by the operator must also demonstrate that it can meet any financial liability that could be incurred as a result of the well activity including both spills and abandoning or terminating the well. The Nova Scotia Offshore Petroleum Installations Regulations enumerate the general safety and design requirements for fixed production installations offshore. Section 42 of this regulation stipulates that the operator incorporate measures necessary to remove the offshore installation without causing significant effect on navigation or the marine environment into the design of the facility where removal of the fixed production installation is a condition of a development plan.

3. Securities/Financial Assurances

This section of the report summarize the basis for financial assurance within the mining and petroleum sectors, how financial securities are calculated, and the forms of security Nova Scotia accepts. Financial assurance requirements associated with resources under federal jurisdiction are not included in this section. Such requirements are provided in a separate federal report.

3.1 Securities/ Financial Assurance

3.1.1 Mining Sector

In accordance with Section 77 of the Mineral Resources Regulation and Section 65 of the Environment Act, mine licensees must post a reclamation security concomitant with submittal of a mine license to the Department of Natural Resources Geosciences and Mines Branch, Minerals Management Division and submittal of a rehabilitation plan to Department of Environment. The amount of security required is determined jointly by the Department of Environment and the Department of Natural Resources, with the security being held by either department. The amount of security is determined on a site-specific basis. A mine reclamation security, referred to as a reclamation bond, must account for costs for labour, equipment, supplies, and services necessary to remove all infrastructures, as well as those necessary for completing site contouring, re-vegetation, and proper site drainage. Cost estimates for the removal of infrastructures must account for the removal of buildings: foundations: and filling pits, declines, and shafts. The estimated cost of reclamation is included in an engineering plan, which is written by the mine operator. Security deposits are evaluated and potentially adjusted every 2 years.

3.1.2 Coal, Pit, and Quarry Securities

Reclamation security is required by the Department of Natural Resources and the Department of Environment under the Mineral Resource Act and the Environment Act, respectively. Both agencies share responsibility in review and approval of surface coal mine reclamation plans. These plans should be practical, achievable, and include input from the community around the site area. The overall objective of these plans is to produce a landscape that is safe, stable, and compatible with the local surroundings.

3.1.3 Petroleum Securities

3.1.3.1 Onshore Oil and Gas

Section 16 of the Onshore Petroleum Drilling Regulations stipulates that a security deposit be posted prior to the commencement of any drilling. The amount of financial security must cover the cost to abandon the well and leave the drill site in a satisfactory condition. The operator must demonstrate that they have the financial resources to meet any liability that may be incurred as a result of the drilling of the well (Government of Nova Scotia 2013d). Section 8(1) of the Geophysical Exploration Regulations stipulates that a security must be posted in an amount specified by the Minister of Energy to cover damages incurred during exploration. Security stipulations required for gas plants are found in Section 15(4) of the Gas Plant Facility Regulations.

3.1.3.2 Offshore Oil and Gas

Financial assurance or responsibility for offshore exploration, development, and production activities, as well as for spills and debris, is required for offshore oil and gas activities. For spills and debris, evidence of financial responsibility in the amount of $30 million dollars Canadian (CDN) must be provided. An operator, along with its interest holders and parties, must submit a decommissioning program that includes evidence of financial responsibility for decommissioning. This decommissioning program must be submitted to the CNSOPB 6 months prior to commencing production. The following information must be included in the decommissioning program document:

- Projected cost associated with the abandonment of the wells and the decommissioning of the production installation

- Manner and form in which the operator will ensure, on behalf of the interest owner, that the abandonment/decommissioning costs will be paid
- Manner, form, and associated costs in which the decommissioned production installation will be maintained (in the event that entire removal is not required)
- Manner and form in which any residual liability will be dealt with by the operator and interest owner, in the event any subsequent claims arise after such abandonment/decommissioning occurs, with respect to damages attributable to the operator's work or activity
- Such other information as the Board may consider necessary (Government of Canada 2000).

3.2 Calculation of Securities/Financial Assurance

3.2.1 Mining Sector

All new mines and quarries are required to provide minimum interim security of $6,250 CDN per hectare ($2,530 CDN per acre) of disturbed area for pits and quarries (Campbell 2013). Before the interim development phase ends, the mine operator must submit a rehabilitation plan which will include an estimated total for the labour, equipment, supplies, and services to rehabilitate the site back to its original condition. The amount of security after the interim development phase is calculated on a site-specific basis, with the final amount being approved by the Department of Natural Resources and Department of Environment. Currently, the Mines Branch does not provide clear guidelines for staff or mine operators to use in calculating securities.

3.2.2 Petroleum Sector

3.2.2.1 Onshore

For onshore exploration activities, a fixed amount of 20 percent of the value of the Work Program for each year that the agreement is in effect must be posted as a security payment. If the holder wants to modify the Work Program, resulting in an increase in its value, the Minister of Energy may require an additional sum to secure the performance of the holder by means of an additional irrevocable letter of credit or an increase in value of the original letter of credit.

3.2.2.2 Offshore

Guidance concerning how the CNSOPB estimates security requirements related to spills and debris is readily available; however, guidance for estimating the amount of security required for abandonment of wells and facilities are less available. The following information was provided via email from Christine Bonnell-Eisnor, Director, Regulatory Affairs and Finance, concerning the determination of offshore security amounts for DR&R activities:

> *"In terms of decommissioning, the CNSOPB requires that the operator, on behalf of the participating interest holders and parties, to submit a decommissioning program for the CNSOPB to approve, including its proposed evidence of financial responsibility. Since each project and production installation is different, the requirements respecting evidence of financial responsibility is dealt with on a case by case basis. Therefore, operators are strongly encouraged to consult with CNSOPB staff regarding forms of financial responsibility prior to submitting the documentation to the Board for approval.*
>
> *In some cases the decommissioning/abandonment of an installation can present areas of concern and ongoing liability, for example well bore and seafloor ongoing liability. In the past operators have entered into discussions with the CNSOPB regarding financial responsibility for post decommissioning ongoing liability. Financial responsibility documents are held until monitoring programs have been completed and the CNSOPB is satisfied that abandoned materials remain in place. Again, since each project and production installation is different, the requirements respecting evidence of financial responsibility, and the associated amounts, are dealt with on a case by case basis.*"

For spills and debris, three options are available for claimants for recovery of actual loss or damage that can be attributable to an offshore operator: voluntary settlement by operator, application to CNSOPB for compensation, or civil suit. The preferred option, which should be pursued first, is to pursue a settlement with the operator. In order to provide compensation funds under the second option, the CNSOPB requires each operator to provide proper financial security in the amount of $30 million CDN. The security provided by the operator is required to cover damages incurred as a result of spills, discharges of petroleum, or debris from oil and gas operations. For damages that cannot be attributed to a specific offshore operator, there are two mechanisms that can be pursued by a claimant: Canadian Association of Petroleum Producers' Commercial Fisheries Compensation Program for Loss Resulting from Non-Attributable Gear and Vessel Damage and the Ship-Source Oil Pollution Fund.

3.3 Forms of Security/Financial Assurance

3.3.1 Mining Sector

The Mines Branch accepts cash, letter of credit from a bank, bonds from a third party, or other forms of security deemed acceptable by the Minister of Natural Resources. Cash securities are held in a special account by the Department of Finance or Registrar. The Registrar and Department of Finance also hold other forms of security posted by mine operators.

3.3.2 Petroleum Sector

Securities in the form of an irrevocable letter of credit are accepted for exploration licenses.

4. ExxonMobil Sable Offshore Energy Project

The Sable Offshore Energy Project (SOEP), which has 21 wells drilled across five wellhead platforms, began production in 1999. With an initial estimated life span of 25 years, the SOEP was expected to reach its end of life by 2025 (ExxonMobil 2014). However, with the recent notice for the expression of interest for supply of well plug and abandonment equipment in February 2014, as well as a bid solicitation issued to provide environmental support for the abandonment of the SOEP, it appears the project will not be operated through 2025. Early planning for plug and abandonment work is expected to begin in 2015.

Costs associated with shutting down a project like Sable are often difficult to determine, but Pengrowth has indicated to its unit holders that it has prepaid $ 55 million CDN for its share of the cost of decommissioning (IPOANS 2014). The abandonment of the SOEP will be an interesting undertaking to follow by the Alaska Department of Natural Resources given the number of platforms present in the Cook Inlet. The events associated with the DR&R activities for the SOEP should provide many lessons and insights to apply to Alaska.

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CANADIAN PROVINCIAL REPORT—NUNAVUT

1. Background and History

Nunavut is a Canadian territory created as a result of the Nunavut Land Claims Agreement established in April 1999. Nunavut spans 2 million square kilometres and consists of 25 communities with a total population of approximately 36,000 people, 85 percent of which are Inuit. Nunavut is recognized as one of Canada's most attractive jurisdictions for mineral and petroleum exploration, with residents having benefited significantly from mine development, exploration, and gold production. Exploration and development activities have resulted in substantial spending by both major multinational mining companies and junior exploration companies in Nunavut. Nunavut has been subdivided into three administrative districts, referred to as regions:

- Kitikmeot region
- Kivalliq region
- Qikiqtani region

The Qikiqtani region, formerly referred to as the Baffin Region, is Nunavut's largest administrative district . This region comprises the eastern area of Nunavut and consists of Baffin Island, the Belcher Islands, Akimiski Island, Mansel Island, Prince Charles Island, Bylot Island, Devon Island, Cornwallis Island, Bathurst Island, Amund Ringes Island, Ellef Ringes Island, Axel Heiberg Island, Ellesmere Island, the Melville Peninsula, the eastern part of Melville Island, and the northern parts of Prince of Wales Island and Somerset Island, plus smaller islands in between.

The Kitikmeot region is the second largest administrative district. It is located in the western region of Nunavut. It consists of the southern and eastern parts of Victoria Island with the adjacent part of the Nunavut mainland as far as the Boothia peninsula. King William Island and the southern portion of Prince of Wales Island are part of the Kitikmeot region as well.

Kivalliq is the central region in Nunavut and is located northwest of Hudson Bay. The region shares a border with the Northwest Territories and Manitoba, and is the smallest of the three regions. The Kivalliq region consists of the portion of the mainland to the west of Hudson Bay together with Southampton Island and Coats Island. Before 1999, Kivalliq region existed under slightly different boundaries as Keewatin region, Northwest Territories.

1.1 Mining Sector

The Qikiqtani region hosts a range of mineral deposits and occurrences, including iron, base metals, gold, platinum-group elements, diamonds, and sapphires. The region has two past-producing mines: Nanisivik on northern Baffin Island (which produced zinc, lead, and silver) and the Polaris lead-zinc mine on Little Cornwallis Island.

The main commodities of interest in the Kitikmeot region include gold, zinc, and copper, but the region is also known to host diamonds, platinum group elements, and uranium. Past-producing mines in the Kitikmeot region include the Roberts Bay and Ida Bay silver mines, the Hope Bay gold project, the Lupin gold mine, and the Jericho diamond mine.

The Kivalliq region's diverse geology hosts a number of mineral occurrences and deposits, particularly gold, uranium, nickel, and platinum group elements; base metals; rare earth elements; and diamonds. Past-producing mines in the region include the North Rankin Nickel mine and the Cullaton/Shear Lake gold mine. Currently, there is only one operating mine in the Kivalliq region, the Meadowbank gold mine, operated by Agnico-Eagle Mines Limited.

1.2 Petroleum Sector

Petroleum exploration in Nunavut began in 1962 with a flurry of activity occurring until 1986. Nunavut is estimated to have approximately a third of Canada's total petroleum resources, with an estimated total of almost 2 billion barrels of crude oil and 27 trillion cubic feet of natural gas with undiscovered resources believed to be many times more abundant than currently known.

2. Regulatory Structure

2.1 Governmental Agencies

There are three governmental jurisdictions operating in Nunavut, all of which have some level of authority over how resource development occurs there. More importantly, these governing bodies have some level of influence and authority over how post-development site restoration, reclamation, and restoration takes place in Nunavut. These entities are: the Government of Canada; the Government of Nunavut; and the Inuit, represented by the Nunavut Tunngavik Incorporated (NTI) or its Designated Inuit Organizations (DIOs). Most of the authority related to resource development and post-development restoration remains with the Government of Canada. However, some of these responsibilities have devolved or are in the process of being devolved to the Government of Nunavut. In a parallel process, the Inuit of Nunavut are working towards achieving more autonomy and self-determination through self-government. This process differs from devolution, which involves transferring authority from a central government (Government of Canada) to a lower-level government, such as a province or in this case the Government of Nunavut. Final devolution of the management of Nunavut's natural resources has not been fully realized. Until final devolution has occurred, a majority of the Nunavut territory remains under the Government of Canada's control.

Currently, there are three classifications of land in Nunavut: Commissioner's land, Crown lands, and Inuit Owned Lands (IOLs). Each of these land ownership classifications is administered by separate jurisdictions with respect to land use and permitting. Aboriginal Affairs and Northern Development Canada (AANDC), which represents the Government of Canada, has jurisdiction over Crown lands (federal), while the Government of Nunavut has jurisdiction over Commissioner's lands. DIOs have jurisdiction over all surface rights on IOL, but jurisdiction over subsurface rights for IOL were not universally granted. A majority of the subsurface rights on IOL were retained by the Government of Canada, with only a portion of IOL lands being granted both surface and subsurface rights. As such, AANDC is responsible for permitting mining and petroleum resources on IOL for which NTI and DIOs were not granted subsurface rights, while the NTI and DIO administer permits for the IOL, for which it has both surface and subsurface rights.

2.1.1 Crown Lands

More than 80 percent of Nunavut lands are currently designated as Crown lands and are under the authority of the Government of Canada. The Government of Nunavut works with the Government of Canada in a co-manager role to manage its natural resources on these lands with the expectation that these responsibilities will eventually devolve. Once devolution occurs, the Government of Nunavut will take responsibility for managing these lands and their natural resources, creating governmental agencies that will take on the roles currently performed by the AANDC.

2.1.2 Commissioner's Lands

Only about 1 percent of Nunavut is classified as Commissioner lands. These lands are under the control of the Government of Nunavut.

The Territorial Department of Economic Development and Transportation, Mineral and Petroleum Resources Division (MPRD) is responsible for encouraging and supporting the development of sustainable mining and petroleum industries on Commissioner's lands in Nunavut. The MPRD has been tasked with the development of a streamlined permitting, regulatory regime, and legislation to support resource management and development as part of its ongoing commitment to the devolution process. The MPRD collects, maintains, and disseminates geoscience information for Nunavut. It is responsible for providing financial and technical support for prospectors, as well as enhancing investor confidence in Nunavut and serving as a liaison with key players including industry, local service sectors, and potential workforce participants. The Nunavut Department of Environment is involved with regulating the environmental aspects of resource development as well. The MPRD currently administers five programs related to resource development:

- Small business support program
- Strategic investments program

- Nunavut prospectors program
- Carving stone program
- Independent science program for youth.

2.1.3 Inuit Owned Lands

The administration of all surface land-related matters on IOL is the responsibility of the Qikiqtani Inuit Association (Qikiqtani region), Kivalliq Inuit Association (Kivalliq region) and Kitikmeot Inuit Association (Kitikmeot region). Authorization is required in order to access and occupy these lands for the purposes of any private, commercial, or public venture including resource development. Each of these organizations are responsible for issuing licenses and land leases, inspecting all activities authorized under a license or land lease, and enforcing regulations pertinent to the use of these IOL.

The Qikiqtani Inuit Association Lands and Resources Department is responsible for administering land and resources practices on its IOL and serves as a liaison with Community Lands and Resources Committees (CLARCs). The Qikiqtani Inuit Association Lands and Resource Department provides advice on land and resource issues. It is responsible for developing policies and procedures for land and resource development as well. The Qikiqtani Inuit Association maintains records and a filing system of information pertinent to the Department of Lands and Resources. The Lands and Resources Department is also in charge of the proposed Lancaster Sound National Marine Conservation Area. According to the association's website, the number of land use applications in the Qikiqtani region has increased greatly with the Department of Lands and Resources having issued a number of exploration permits in the region to companies prospecting for base metals, gold, and diamonds.

The Kivalliq Inuit Association Lands Department is responsible for issuing licenses and land leases to access and develop its IOL, as well as conducting land inspections and monitoring land use activities in the region. It is responsible for reviewing mine development plans. The Kivalliq Inuit Association ensures that its communities and CLARCs are consulted concerning land use and development matters. The association serves as a liaison with other resource management boards, organizations, and companies activities in the region as well. The Kivalliq Inuit Association develops and implements policies and procedures for land management in coordination with the other Regional Inuit Associations and the NTI. It is also working on obtaining funding to implement an environmental cleanup strategy for both IOL and Crown lands in its region.

The Kitikmeot Inuit Association's Department of Lands, Environment, and Resource Development is responsible for the administration of IOL in the region and the negotiation and permitting of proposed developments. Proponents of development on IOL in the Kitikmeot region must complete an Access to Inuit Owned Land application. Once reviewed, projects deemed socially and environmentally acceptable proceed to regulatory approval, subject to the terms of the IOL Land Use License. Proposed projects must receive approval from all appropriate regulatory boards (e.g., land, water, environmental impact) and are subject to any terms and conditions applied. The Kitikmeot Inuit Association monitors all ongoing projects and routinely conducts land use inspections to ensure compliance with the Land Use License and all other Agreements.

2.1.4 Crown Lands

Mineral and petroleum resources located on Crown lands in Nunavut remain under the jurisdiction of the Canadian Federal Government through AANDC. The Nunavut Regional Office (NRO) of AANDC is responsible for the Nunavut region. The NRO works with residents to manage land, water, and mineral resources, and to remediate contaminated sites. The mission of the NRO is: "*to work in partnership to help improve the quality of life of Nunavummiut through economic and social development, environmental stewardship and effective management of natural resources.*"

2.1.4.1 Mining Sector

Land, water, and mineral resources on Crown lands are managed through the AANDC NRO Operations Directorate. The Directorate has five divisions. The Mineral Resources Division manages sustainable mineral resource development on Nunavut's Crown land. The Northern Minerals Resource Directorate, which is within the AANDC, is involved with minerals management as well.

The AANDC Mining Recorder's Office is responsible for:

- Subsurface rights administration of Crown land
- Administration of the Territorial Coal Regulations including issuance of exploration licenses, leases, and permits
- Licenses and permits for prospecting, mining claims, and leases.

The Contaminated Sites Directorate manages contaminated sites located on Crown land in Nunavut that fall under AANDC's control. This is done by identifying waste/contaminated sites located on Crown land for which the Department is liable, assessing environmental impacts, cleaning up and managing contaminated sites on a priority basis, providing advice to residents North of 60°, and educating Nunavummiut (residents of Nunavut) on contaminants.

2.1.4.2 Petroleum Sector

AANDC's Northern Petroleum Resources Directorate (NPRD) is responsible for the management of oil and gas resources on Crown lands in the Nunavut region and the northern offshore areas. The NPRD is responsible for the issuance and management of exploration licenses, significant discovery licenses, and production licenses. It approves benefit plans submitted as part of the licensing process before oil and gas development takes place. The NPRD is responsible for maintaining the oil and gas rights registry, as well as developing the regulatory environment for managing petroleum resources in Nunavut. It is also responsible for setting and collecting royalties. Finally, the NPRD is responsible for ensuring that financial assurance requirements are fulfilled prior to licenses being issued.

2.2 Statutory and Regulatory Framework

2.2.1 Devolution

The Government of Nunavut is currently undergoing the process of devolution. Devolution is the transfer of federal jurisdiction over Nunavut's lands, resources, and inland waters to the Government of Nunavut. Devolution is a separate process from Aboriginal self-government, which is being addressed in land claim and self-governance agreements. The first significant milestone in the Nunavut devolution process occurred in 2008 with the signing of the Lands and Resources Devolution Negotiation Protocol. This protocol was signed by the Government of Canada, the Government of Nunavut, and NTI. The NTI ensures that promises made under the Nunavut Land Claims Agreement are carried out and is the legal representative of the Inuit of Nunavut. The protocol, along with the work of the Chief Federal Negotiator appointed in May 2012, will serve as a foundation for future negotiations required to accomplish final devolution. The next milestone would be an agreement-in-principle followed by a final transfer agreement. A series of legislative changes will occur once the final transfer agreement has been signed. After the Nunavut mining and petroleum statutes and regulations are established, an implementation plan will be developed. Once devolution has been fully implemented, Nunavut will assume management responsibility for lands currently designated as Crown lands as well. Until that time, a majority of the lands in Nunavut remain under federal jurisdiction and are subject to Government of Canada statutes and regulations.

2.2.2 Commissioner's Lands

Development of a Mines Act and a Mineral Tenure Act that mirror the federal statutes has not been initiated by the Government of Nunavut because the devolution process has not progressed far enough to justify working on this legislation. Nunavut oil and gas statutes have not been developed for the same reason. As such, Nunavut mining and petroleum resources still fall under federal jurisdiction. Federal statutes and regulations specific to Nunavut are described below. Petroleum statutes and regulations that would be enacted by the Government of Nunavut have not been written for the same reason.

2.2.3 Crown Lands

Several statutes form the basis for mineral exploration, development, production, and reclamation requirements in Nunavut. The basis for regulation of all Crown lands in Nunavut is the Territorial Lands Act, which was originally passed in 1952. However, it is the Nunavut Waters and Nunavut Surface Rights Tribunal Act (enacted in 2002) that identifies the security requirements for conducting mining on Crown lands in Nunavut. The security provisions, enumerated in Section 76 of the statute, require a licensee to furnish and maintain security in the amount prescribed or determined on the basis of the regulations or satisfaction of the Minister of AANDC. Section 76 stipulates to whom the security funds can be issued for compensation, the limitations of the security, and the conditions under which the security funds can be released to the licensee who originally posted it.

Section 82(1)(i) of the Nunavut Waters and Nunavut Surface Rights Tribunal Act provides the statutory basis for the promulgation of regulations that prescribe the form and nature of securities, as well as the terms and conditions on which it will be furnished and maintained. Section 82(1)(i) also sets out the basis for the Minister to write regulations to prescribe the amount and manner in which that the security is determined.

In 2002, the Nunavut Waters and Nunavut Surface Rights Tribunal Act was passed, formally establishing the Nunavut Water Board and the Surface Rights Tribunal. Sections 139(a)(vi) and 146(a)(vi) of the Act allows for the Nunavut Surface Rights Tribunal to include security requirements in the terms of an entry order and right-of-way access orders it issues, respectively.

The Nunavut Mining Regulations apply to Crown lands in Nunavut, including lands under the administration and control of the Commissioner of Nunavut. Petroleum resource management on Crown lands in Nunavut is exercised under two federal statutes: the Canada Petroleum Resources Act (CPRA) and the Canada Oil and Gas Operations Act (COGOA).

3. Security Bonding/Financial Assurance

3.1 Summary

Mine and petroleum operators are required to prepare closure plans prior to being allowed to proceed with construction of production facilities. These operators are also required to post a security, which will cover the cost of reclaiming the site, and which represents a significant up-front cost. The security must be posted before the regulatory agencies described above will issue an authorization or permit for the proposed activity.

3.1.1 Commissioner's and Crown Lands

Section 31(1)(j) of the Territorial Lands Act Regulation allows for the deposit of a security as a term and condition of a land use permit. Financial assurance and a demonstration of financial fitness must be submitted before mining or oil and gas activities can occur. The full amount of security must be posted at that time with the exception of a few cases in which a security deposit has been accepted in installment payments. In cases where installment payments were made, the amount of security was required to reflect liability at a given time period. The Minister of AANDC holds the security in a Mining Reclamation Trust.

3.1.2 Inuit Owned Lands

The Qikiqtani Inuit Association Department of Lands and Resources is responsible for issuing land use licenses and permits. It requires tenants to prepare an Abandonment and Reclamation Plan (ARP) for access to its lands for all exploration and development projects. The tenant must outline the plans and process it will undertake to reclaim IOL to a level acceptable for the Qikiqtani Inuit Association and provide a financial security deposit to address any potential reclamation liabilities associated with the project.

Projects approved on IOL in the Kitikmeot region must provide a reclamation security deposit to the Kitikmeot Inuit Association reflecting the projected costs for complete reclamation of the project site. The Kitikmeot Inuit Association will return the security deposit on satisfactory completion of the project site reclamation. If a site is not reclaimed to the satisfaction of the Kitikmeot Inuit Association, site reclamation will be accomplished through funds held in the security deposit. Any unused funds will be returned to the project proponent.

The Kivalliq Inuit Association Lands Department is responsible for issuing licenses, land leases, and other development activities on IOL lands within its region. It reviews plans for mine development and monitors land use activity. It also ensures that communities and CLARCs are consulted during the permitting process. The Kivalliq Inuit Association Lands Department works in concert with its investment arm, the Sakku Investment Corporation, to promote responsible land resource-based economic development for mining companies.

3.2 Calculation of Securities

3.2.1 Commissioner's Lands

Under Section 36 of the Territorial Lands Act Regulation, a security deposit not to exceed $100,000 CDN must be posted prior to a permittee beginning a land use operation for which a security is required. However, because only about 1 percent of Nunavut is currently classified as Commissioner's lands, this security requirement is rarely applied.

3.2.2 Crown Lands

Currently, the AANDC uses the RECLAIM tool to calculate closure costs and set security requirements for mining operations on Crown lands in Nunavut. The estimate generated from this model is then used to determine the amount of security required for a mine. The model is developed in Microsoft Excel with multiple interconnected spreadsheets and embedded calculations. Individual spreadsheets correspond to various aspects of the mine's operation, such as the tailings pond, rock piles, open pits, buildings, and water treatment facilities. All of the costs generated for each of these spreadsheets are summed into a single spreadsheet that presents a summary of costs.

According to Nathen Richea, Manager of Water Regulatory Water Resources Division for the Government of the Northwest Territories (GNWT), the RECLAIM model was developed when it became apparent to that a tool needed to be developed to calculate securities, particularly for major undertakings (Nathan Richea, pers. comm. August 5, 2014). It was acknowledged that the model also needed to be designed to cover the costs the GNWT would incur to reclaim a given mine site and help validate the costs being provided by the mine operators, including costs for reclaiming remote sites. Logistical costs associated with remote reclamation work were often excluded from the mine operators cost estimates in the past. Version 1 of the RECLAM Model was issued in the late 1990s. Each version of the model incorporates lessons learned, particularly as actual reclamation costs to clean up abandoned properties are incurred. The current version of the model builds upon the Mine Site Reclamation Policy for the NWT (2002). A copy of the RECLAIM Model Version 7.0 (in Microsoft Excel) and the User Manual are provided as Appendix A and B, respectively to this report.

3.2.3 Inuit Owned Lands

The Qikiqtani Inuit Association requires that a tenant provide a detailed estimate to substantiate the amount of financial security it deposits for a project on IOL. The QIA's position is that RECLAIM model, which is commonly used for estimating reclamation costs, does not offer a fully transparent assessment of security costs and is not considered to be in the best interest of the Inuit. Therefore, the Qikiqtani Inuit Association prefers that other methods or tools for calculating the cost of reclamation activities be used. Security costs should equal 100 percent of the cost for an independent third-party contractor to reclaim the site. The Qikiqtani Inuit Association reserves the right to conduct an independent security estimate for the proposed project. The Qikiqtani Inuit Association may elect to use probabilistic methods to aid in understanding the impact of assumptions and uncertainties in the input values on the security value. The Qikiqtani Inuit Association may elect to use an approved proprietary model, such as RE$TORE, to develop a deterministic and probabilistic financial security estimate, as well as to understand its risk. The Qikiqtani Inuit Association has prepared a nine-page abandonment and reclamation policy that provides guidance for estimating reclamation costs, which is provided as Appendix A to this report. Other DIOs did not have similar guidance posted on their association websites.

3.3 Forms of Security

3.3.1 Commissioner's and Crown Lands

Section 36(3) of the Territorial Lands Act Regulation allows for the following forms of security:

- Promissory note guaranteed by a chartered bank and payable to the Receiver General
- Certified check drawn on a chartered bank in Canada and payable to the Receiver General

- Bearer bonds issued or guaranteed by the Government of Canada
- A combination of the three securities described above.

3.3.2 Inuit Owned Lands

The Qikiqtani Inuit Association accepts securities in a form that is readily available to it, retains its value throughout the land use activity, and is beyond the control of the land user or its creditors in the event of insolvency. The other DIOs did not provide information concerning the form of securities they accept.

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APPENDIX A

RECLAIM MODEL VERSION 7.0 (MAY 2014)

Project Name:	**Reclaim Model - Overview of Program**
Blank	**All users are urged to read the Reclaim Model User Manual - Scroll down for overview description of program.**

Important! Reclaim 7.0 works better with no other excel files open.
If other excel files are open ignore run time error and proceed

Reclaim Menu	The default Excel menu bar has an additional tab labelled "Add-Ins" that provides options specific to the Reclaim Model.
Clear	This option deletes all input data, deletes any duplicated elements and blanks out the project name. It also allows for segregation into land costs vs water costs if required.
Duplicate	This option Duplicates components of the project. E.g. if there is more than one Open Pit, use duplicate to add a second Open Pit. Quantities for the new Open Pit are erased, but the Activities and Cost Codes are carried over from the original Open Pit. The new Open Pit subtotal is added to the Summary page.
Unit Costs	This option opens a window of unit costs to provide easy reference. NOTE: the unit cost table has a filter in the 'UNITS' column. You can select to only see a particular unit (eg km) or multiple units (km and m3) or all units.
Print All	This option prints the Summary Worksheet, Unit Cost Worksheet, and the individual component worksheets having non-zero balances. Individual worksheets can be printed directly using standard printing methods, such as Ctl - P.
Quit	Select Quit to exit the program
Help	Redirects user to Instructions worksheet.

WorkSheets	
Summary	This worksheet contains a cumulative summary of costs for each component of the project. Associated costs such as engineering and project management are added as a percentage of the component costs.
Components	Costs are derived for individual closure and reclamation activities by multiplying a "quantity" of activity by a "unit cost". An activity can be edited, added, or deleted from worksheet. However, care should be taken not to modify cells that are defined and used elsewhere in the program. ***Do not change the content or column width of the first column of each component worksheet.***
Unit Costs	This worksheet contains a look up table with costs for typical work associated with each closure and reclamation activity

Limitations	***The Reclaim Program will NOT work if the worksheets are changed such that the following requirements are not met. Please review the following prior to modifiying worksheets.***
WorkSheet Names	*The names of the worksheets must not be changed.*
Defined Names	Certain cells have defined names, which must not be changed. Where the cell is named, the name will appear in the "Name Box" to the left of the formula bar.
First line of data	The first line of data for any component worksheet starts on line 4. ***Do not change the first line of a component worksheet, ie the component name.***
Cell A1	Cell A1 on the component sheet MUST always contain the count of that component for the duplicate function to operate. ***DO NOT CHANGE.***
Adding Lines	You can add lines to components and the unit cost table, as long as they are not the last lines. The last line might fall outside the named ranges. You can check the size of the named range by selecting the name from the drop down box at the top left of the sheet. Usually this box has a cell reference, or a name.
Printing	A component will only be printed if its sub-total is greater than zero. In addition, a component and the summary sheet cannot be printed if there is an error. Printing has been set to print 1 page per component.

Conditions of Use	The Reclamation Cost Estimating Model was prepared to serve as a guide for Government Agencies, mining companies, and others to estimate the cost of mine reclamation. This model is not intended to replace reclamation planning or to be used to determine the activities required to reclaim a site or to dictate how much should be spent on reclamation. Reclaim was prepared by Brodie Consulting Ltd. on behalf of AANDC. AANDC and Brodie Consulting Ltd. are not responsible for the completeness or accuracy of any reclamation estimate made using this model. The user agrees to check and take responsibility for all aspects of any cost estimate made using this model.

The following table provides guidance as to whether water management and treatment is considered short term or long term. Short term closure activities may be costed within a component (eg 'Open Pit' or 'Rock Pile') or 'Water Management'. Long term or post-closure water treatment is costed in 'Water Treatment'. and included in "Post-closure Monitoring and Maintenance".

		Short Term/ Capital Ex	**Long term**
Open Pit	flood pit - install/operate pumping system	x	
	construct diversion ditches	x	
	treat 1st filling	x	
	install pump/decant system	x	
	passive/biological treatment	x	
	overflow treatment		x
Rock Pile/Heap Leach Facility	construct diversion ditches	x	
	install groundwater collection system	x	
	install toe seepage collection system	x	
	collect and treat groundwater		x
	collect and treat seepage (ARD/ML)		x
	install passive treatment system	x	
	operate and maintain passive treatment system		x
	operate pump and detoxify heap leach pile (cyanide destruction)	x	
Tailings Facility	construct diversion ditches	x	
	pump supernatant (to pit, U/G)	x	
	treat supernatant	x	
	install toe seepage collection system	x	
	collect and treat seepage (ARD/ML)		x
	install passive treatment system	x	
	operate and maintain passive treatment system		x
U/G Mine	accelerate flooding	x	
	install seepage collection system	x	
	install dewatering/pumping system	x	
	operate seepage/dewatering system (ARD/ML)		x
Water Management	refill lakes		
	redirect creeks/streams	x	
	stabilize water management ponds	x	
	stabilize/close sediment ponds	x	
	fresh water supply - breach embankment	x	
	fresh water supply - remove piping system	x	
	construct water treatment plant	x	
	construct sludge pond	x	
	water control in reclamation quarry	x	
	operate/maintain water treatment plant		x

SUMMARY OF COSTS

CAPITAL COSTS	COMPONENT NAME	COST	LAND LIABILITY	WATER LIABILITY
OPEN PIT		$0	$0	$0
UNDERGROUND MINE		$0	$0	$0
TAILINGS FACILITY		$0	$0	$0
ROCK PILE		$0	$0	$0
BUILDINGS AND EQUIPMENT		$0	$0	$0
CHEMICALS AND CONTAMINATED SOIL MANAGEMEN		$0	$0	$0
SURFACE AND GROUNDWATER MANAGEMENT		$0	-	$0
INTERIM CARE AND MAINTENANCE		$0	-	$0
	SUBTOTAL: Capital Costs	**$0**	**$0**	**$0**
	PERCENT OF SUBTOTAL		**0%**	**0%**

INDIRECT COSTS		COST	LAND LIABILITY	WATER LIABILITY
MOBILIZATION/DEMOBILIZATION		$0	$0	$0
POST-CLOSURE MONITORING AND MAINTENANCE		$0	$0	$0
ENGINEERING	5%	$0	$0	$0
PROJECT MANAGEMENT	5%	$0	$0	$0
HEALTH AND SAFETY PLANS/MONITORING & QA/QC	1%	$0	$0	$0
BONDING/INSURANCE	1%	$0	$0	$0
CONTINGENCY	20%	$0	$0	$0
MARKET PRICE FACTOR ADJUSTMENT	0%	$0	$0	$0
	SUBTOTAL: Indirect Costs	**$0**	**$0**	**$0**

TOTAL COSTS		**$0**	**$0**	**$0**

1 **Open Pit Name:** **Pit # *1***

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost	% Land	Land Cost	Water Cost
CONTROL ACCESS									
Fence		m		#N/A	$0.00	$0		$0	$0
Signs		each		#N/A	$0.00	$0		$0	$0
Berm at crest		m3		#N/A	$0.00	$0		$0	$0
Block roads		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
STABILITY STUDY									
Conduct stability and setback study		allow		#N/A	$0.00	$0		$0	$0
STABILIZE SLOPES									
Off-load crest, soil A		m3		#N/A	$0.00	$0		$0	$0
Off-load crest, soil B		m3		#N/A	$0.00	$0		$0	$0
Doze/trim overburden at crest		m3		#N/A	$0.00	$0		$0	$0
Drill & blast pit crest		m3		#N/A	$0.00	$0		$0	$0
Buttress slope		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
COVER/CONTOUR SLOPES									
Place fill, soil A		m3		#N/A	$0.00	$0		$0	$0
Place fill, soil B		m3		#N/A	$0.00	$0		$0	$0
Rip rap		m3		#N/A	$0.00	$0		$0	$0
Vegetate slopes		ha		#N/A	$0.00	$0		$0	$0
Vegetate pit floor		ha		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
CONSTRUCT DIVERSION DITCHES									
Excavate ditches -soil		m3		#N/A	$0.00	$0		$0	$0
Excavate ditches -rock		m3		#N/A	$0.00	$0		$0	$0
Rip rap in channel base		m3		#N/A	$0.00	$0		$0	$0
CONSTRUCT SPILLWAY									
Excavate channel		m3		#N/A	$0.00	$0		$0	$0
Concrete		m3		#N/A	$0.00	$0		$0	$0
Rip rap		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
RECLAIM QUARRIES									
Contour slopes		m3		#N/A	$0.00	$0		$0	$0
Place overburden		m3		#N/A	$0.00	$0		$0	$0
Vegetate		m3		#N/A	$0.00	$0		$0	$0
FLOOD PIT-Captital									
Remove stationary equipment (sump pumps)		each		#N/A	$0.00	$0		$0	$0
Remove dewatering pipeline		m		#N/A	$0.00	$0		$0	$0
Remove power lines		each		#N/A	$0.00	$0		$0	$0
Construct diversion ditches		m3		#N/A	$0.00	$0		$0	$0
-Ditch, mat'l A		m3		#N/A	$0.00	$0		$0	$0
-Ditch, mat'l B		m3		#N/A	$0.00	$0		$0	$0
Construct embankment/dam		m3		#N/A	$0.00	$0		$0	$0
Supply/install pump station		each		#N/A	$0.00	$0		$0	$0
Supply/install piping system		m		#N/A	$0.00	$0		$0	$0
Remove pump post-closure		each		#N/A	$0.00	$0		$0	$0
Remove pipeline post-closure		m		#N/A	$0.00	$0		$0	$0
FLOOD PIT-Annual Cost									
Operate pumps (power)		m3		#N/A	$0.00	$0		$0	$0
Maintain pump/pipeline		allow		#N/A	$0.00	$0		$0	$0
Labour:fuel management, comissioning/decom		$/h		#N/A	$0.00	$0		$0	$0
Chemical addition, _____ kg/m3 of water		tonne		#N/A	$0.00	$0		$0	$0
Chemicals, purchase and shipping		tonne		#N/A	$0.00	$0		$0	$0
Passive/biological additives		$/ha		#N/A	$0.00	$0		$0	$0
Passive additives purchase and shipping		tonne		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
					Annual pumping costs	$0			
Number of years of pump flooding		years							
					Total pumping costs	$0		$0	$0
					Total	$0		$0	$0
					% of Total			0%	0%

1 **Underground Mine Name** **UG Mine # *1***

ACTIVITY/MATERIAL	Notes	Unit	Qty	Code	Cost	Cost	Land Cost	Cost
CONTROL ACCESS								
Fence		m		#N/A	$0.00	$0	$0	$0
Signs		each		#N/A	$0.00	$0	$0	$0
Block roads		m3		#N/A	$0.00	$0	$0	$0
Berm		m3		#N/A	$0.00	$0	$0	$0
Concrete wall in portals		m3		#N/A	$0.00	$0	$0	$0
Backfill portal #1		m3		#N/A	$0.00	$0	$0	$0
Backfill portal #2		m3		#N/A	$0.00	$0	$0	$0
Cap raise # 1		m3		#N/A	$0.00	$0	$0	$0
Cap raise #2		m3		#N/A	$0.00	$0	$0	$0
Cap shaft #1		m3		#N/A	$0.00	$0	$0	$0
Cap shaft #2		m3		#N/A	$0.00	$0	$0	$0
Backfill adits		m3		#N/A	$0.00	$0	$0	$0
Backfill open stope		m3		#N/A	$0.00	$0	$0	$0
Concrete cap over open stope		m3		#N/A	$0.00	$0	$0	$0
Other				#N/A	$0.00	$0	$0	$0
REMOVE HAZARDOUS MATERIALS								
Remove hazardous materials, U/G labor		mandays		#N/A	$0.00	$0	$0	$0
Remove/decontam. stationary & elect. equip		mandays		#N/A	$0.00	$0	$0	$0
Remove/decontam. mobile equipment		each		#N/A	$0.00	$0	$0	$0
Remove misc. haz. mat & explosives		kg		#N/A	$0.00	$0	$0	$0
Other				#N/A	$0.00	$0	$0	$0
INSTALL BULKHEADS								
Bulkheads to control water flow		each		#N/A	$0.00	$0	$0	$0
Grout bulkhead		m3		#N/A	$0.00	$0	$0	$0
FLOOD MINE								
Supply/install pump		each		#N/A	$0.00	$0	$0	$0
Supply/install piping system		each		#N/A	$0.00	$0	$0	$0
Operate pumps to flood workings		m3		#N/A	$0.00	$0	$0	$0
Other				#N/A	$0.00	$0	$0	$0
INSTALL GROUNDWATER COLLECTION SYSTEM								
Excavate/install sumps		m2		#N/A	$0.00	$0	$0	$0
Install pumping wells		m3		#N/A	$0.00	$0	$0	$0
Install pumps/pipelines/power supply		LS		#N/A	$0.00	$0	$0	$0
SPECIALIZED ITEMS								
Install water quality monitoring pipes		each		#N/A	$0.00	$0	$0	$0
Install permanent pumping system		each		#N/A	$0.00	$0	$0	$0
Other				#N/A	$0.00	$0	$0	$0
					Total	$0	$0	$0
					% of Total		0%	0%

1 **Tailings Impoundment Name:** **Pond # 1**

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost	% Land	Land Cost	Water Cost
CONTROL ACCESS									
Fence		m		#N/A	$0.00	$0		$0	$0
Signs		each		#N/A	$0.00	$0		$0	$0
Berm		m3		#N/A	$0.00	$0		$0	$0
Block roads		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
STABILIZE EMBANKMENT(S)									
Toe buttress, drainage layer		m3		#N/A	$0.00	$0		$0	$0
Toe buttress, bulk fill		m3		#N/A	$0.00	$0		$0	$0
Rip rap		m3		#N/A	$0.00	$0		$0	$0
Vegetate		ha		#N/A	$0.00	$0		$0	$0
Raise crest		m3		#N/A	$0.00	$0		$0	$0
Flatten slopes		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
COVER TAILINGS									
Grade/shape tailings surface		m3		#N/A	$0.00	$0		$0	$0
Liner bedding		m3		#N/A	$0.00	$0		$0	$0
Subgrade preparation - compact		m2		#N/A	$0.00	$0		$0	$0
Supply geotextile/geosynthetic		m2		#N/A	$0.00	$0		$0	$0
Install geotextile/geosynthetic		m2		#N/A	$0.00	$0		$0	$0
Soil cover		m3		#N/A	$0.00	$0		$0	$0
Rock cover		m3		#N/A	$0.00	$0		$0	$0
Vegetate		m2		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
BURY PAG ROCK									
Relocate PAG rock		m3		#N/A	$0.00	$0		$0	$0
Place cover over PAG rock		m3		#N/A	$0.00	$0		$0	$0
Raise crest of dam		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
STABILIZE DECANT SYSTEM									
Excavate and replace		m3		#N/A	$0.00	$0		$0	$0
Plug/backfill with concrete or clay		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
REMOVE TAILINGS DISCHARGE									
Cyclones		m3		#N/A	$0.00	$0		$0	$0
Pipe		m3		#N/A	$0.00	$0		$0	$0
Remove reclaim barge		allow		#N/A	$0.00	$0		$0	$0
CONSTRUCT DIVERSION DITCHES									
Excavate ditches -soil		m3		#N/A	$0.00	$0		$0	$0
Excavate ditches -rock		m3		#N/A	$0.00	$0		$0	$0
Rip rap in channel base		m3		#N/A	$0.00	$0		$0	$0
FLOOD TAILINGS									
Doze tailings to final contour		m3		#N/A	$0.00	$0		$0	$0
Raise crest of dam		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
UPGRADE SPILLWAY									
Excavate channel, rock		m3		#N/A	$0.00	$0		$0	$0
Excavate channel, soil		m3		#N/A	$0.00	$0		$0	$0
Concrete		m3		#N/A	$0.00	$0		$0	$0
Rip rap		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
CONSTRUCT SEEPAGE COLLECTION POND									
Excavate seepage collection pond		m3		#N/A	$0.00	$0		$0	$0
Doze & spread excavated material		m3		#N/A	$0.00	$0		$0	$0
Vegetate spread material		ha		#N/A	$0.00	$0		$0	$0
Bedding layer		m3		#N/A	$0.00	$0		$0	$0
Supply geomembrane		m2		#N/A	$0.00	$0		$0	$0
Install geomembrane		m2		#N/A	$0.00	$0		$0	$0
Erosion protection layer		m3		#N/A	$0.00	$0		$0	$0
INSTALL GROUNDWATER COLLECTION SYSTEM									
Excavate/install sumps		m3		#N/A	$0.00	$0		$0	$0
Install pumping wells		m3		#N/A	$0.00	$0		$0	$0
Install pumps/pipelines/power supply		LS		#N/A	$0.00	$0		$0	$0
SPECIALIZED ITEMS									
Install permanent instrumentation, supply & technican		each		#N/A	$0.00	$0		$0	$0
Install permanent instrumentation, drilling		each		#N/A	$0.00	$0			$0
TREAT SEEPAGE - see "Water Management" and "Water Treatment"									
TREAT SUPERNATANT									
Pump water (to pit, U/G)		m3		#N/A	$0.00	$0		$0	$0
Equipment maintenance and parts		allow		#N/A	$0.00	$0		$0	$0
Supply reagents		tonne		#N/A	$0.00	$0		$0	$0
				Annual treatment costs		$0			
Number of years of treatment		years							
				Total treatment costs		$0			$0
					Total	$0		$0	$0
					% of Total			0%	0%

* for construction of passive treatment system refer to "Water Management"

1 **Rock Pile Name:**

ACTIVITY/MATERIAL	**Notes**	**Units**	**Quantity**	**Cost Code**	**Unit Cost**	**Cost**	**% Land**	**Land Cost**	**Water Cost**
STABILIZE SLOPES									
Flatten slopes with dozer		m3		#N/A	$0.00	$0		$0	$0
Flatten "bubble dump" areas		m3		#N/A	$0.00	$0		$0	$0
Divert runon, ditch mat'l A		m3		#N/A	$0.00	$0		$0	$0
Divert runon, ditch mat'l B		m3		#N/A	$0.00	$0		$0	$0
Toe buttress, drain mat'l		m3		#N/A	$0.00	$0		$0	$0
Toe buttress, fill mat'l A		m3		#N/A	$0.00	$0		$0	$0
Toe buttress, fill mat'l B		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
COVER ROCK PILE									
Subgrade preparation - doze surface		m3		#N/A	$0.00	$0		$0	$0
Soil cover - excavate,haul,spread&compact		m3		#N/A	$0.00	$0		$0	$0
Rock cover - excavate,haul & spread		m3		#N/A	$0.00	$0		$0	$0
Excavate downslope drainage channel & chute		m3		#N/A	$0.00	$0		$0	$0
Rip rap drainage channel and chute		m3		#N/A	$0.00	$0		$0	$0
Vegetate		ha		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
VERY LOW PERMEABILITY COVER (in addition to above)									
Liner subgrade preparation - compact		m2		#N/A	$0.00	$0		$0	$0
Supply geomembrame		m2		#N/A	$0.00	$0		$0	$0
Install geomembrane		m2		#N/A	$0.00	$0		$0	$0
Protective cover - excavate,haul,spread&compact		m3		#N/A	$0.00	$0		$0	$0
Vegetate		ha		#N/A	$0.00	$0		$0	$0
Install infiltration/seepage instrumentation		allow		#N/A	$0.00	$0		$0	$0
CONSTRUCT DIVERSION DITCHES									
Excavate ditches -soil		m3		#N/A	$0.00	$0		$0	$0
Excavate ditches -rock		m3		#N/A	$0.00	$0		$0	$0
Rip rap in channel base		m3		#N/A	$0.00	$0		$0	$0
CONSTRUCT SEEPAGE COLLECTION POND									
Excavate seepage collection pond		m3		#N/A	$0.00	$0		$0	$0
Doze & spread excavated material		m3		#N/A	$0.00	$0		$0	$0
Vegetate spread material		ha		#N/A	$0.00	$0		$0	$0
Bedding layer		m3		#N/A	$0.00	$0		$0	$0
Supply geomembrane		m2		#N/A	$0.00	$0		$0	$0
Install geomembrane		m2		#N/A	$0.00	$0		$0	$0
Erosion protection layer		m3		#N/A	$0.00	$0		$0	$0
INSTALL GROUNDWATER COLLECTION SYSTEM									
Excavate/install sumps		m3		#N/A	$0.00	$0		$0	$0
Install pumping wells		m3		#N/A	$0.00	$0		$0	$0
Install pumps/pipelines/power supply		allow		#N/A	$0.00	$0		$0	$0
RELOCATE DUMPS									
Load, haul, dump or doze		m3		#N/A	$0.00	$0		$0	$0
Add lime		tonne		#N/A	$0.00	$0		$0	$0
Contour reclaimed area		ha		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
SPECIALIZED ITEMS									
Install permanent instrumentation		each		#N/A	$0.00	$0		$0	$0
Install permanent instrumentation, drilling		each		#N/A	$0.00	$0		$0	$0
TREAT ROCK PILE SEEPAGE - see "Water Treatment"									
HEAP LEACH SEEPAGE TREATMENT - Cyanide Detox									
Cyanide destruction water treatment pumping		m3		#N/A	$0.00	$0		$0	$0
Reagents		tonnes		#N/A	$0.00	$0		$0	$0
Electrician/mechanic to maintain treatment plant		allow		#N/A	$0.00	$0		$0	$0
Equipment maintenance and parts		allow		#N/A	$0.00	$0		$0	$0
				Annual treatment costs		$0			
Number of years of treatment		years							
				Total treatment costs		$0			$0
HEAP LEACH SEEPAGE TREATMENT - ARD/ML**									
Upgrade/modify pumping system - report to WTP		allow		#N/A	$0.00	$0			$0
					Total	$0		$0	$0
					% of Total			0%	0%

* For construction of passive treatment system refer to "Water Management". ARD/ML seepage treatment becomes post-closure water treatment cost

**Heap leach ARD/ML seepage treatment becomes post-closure water treatment cost

1 **Chemicals/Soil Area Name:**

Note: The procedures, equipment and packaging for clean up and removal of chemicals or contaminated soils are highly dependent on the nature of the chemicals and their existing state of containment. Government guidelines should be consulted on an individual chemical basis. Any estimate made here should be considered very rough unless specific evaluations have been conducted.

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost	% Land	Land Cost	Water Cost
HAZARDOUS MATERIALS AUDIT									
Hazardous materials audit		mandays		#N/A	$0.00	$0		$0	$0
BUILDING DECONTAMINATION & CONSOLIDATION OF HAZARDOUS MATERIALS									
Environmental technician/coordinator		mandays		#N/A	$0.00	$0		$0	$0
Decontaminate: oil, fuel		mandays		#N/A	$0.00	$0		$0	$0
Decontaminate maintenance shop		mandays		#N/A	$0.00	$0		$0	$0
Decontaminate power plant		mandays		#N/A	$0.00	$0		$0	$0
Decontaminate bulk fuel storage		mandays		#N/A	$0.00	$0		$0	$0
Decontaminate ANFO plant		mandays		#N/A	$0.00	$0		$0	$0
Decontaminate offices/warehouse/accom		mandays		#N/A	$0.00	$0		$0	$0
Removal of asbestos siding on buildings		m2		#N/A	$0.00	$0		$0	$0
Removal of friable asbestos on equipment		m2		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
HAZARDOUS MATERIALS REMOVAL									
Waste oils		litre		#N/A	$0.00	$0		$0	$0
Waste fuel		litre		#N/A	$0.00	$0		$0	$0
Waste batteries		kg		#N/A	$0.00	$0		$0	$0
Assay & environmental lab reagents		kg		#N/A	$0.00	$0		$0	$0
Machine shop paints, solvents etc		litre		#N/A	$0.00	$0		$0	$0
Glycol		litre		#N/A	$0.00	$0		$0	$0
Process reagents		kg		#N/A	$0.00	$0		$0	$0
Nuclear sources		allow		#N/A	$0.00	$0		$0	$0
Other hazardous materials		allow		#N/A	$0.00	$0		$0	$0
HAZARDOUS MATERIALS									
Transportation to disposal facility		allow		#N/A	$0.00	$0		$0	$0
Disposal fees		allow		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
CONTAMINATED SOILS									
Contam. soil investigation - Phase 1		each		#N/A	$0.00	$0		$0	$0
Contam. soil investigation - Phase 2		each		#N/A	$0.00	$0		$0	$0
CONTAMINATED SOIL REMOVAL									
Excavate and transport to onsite facility		m3		#N/A	$0.00	$0		$0	$0
Manage hydrocarbon remediation at facility		m3		#N/A	$0.00	$0		$0	$0
Reagents/stabilizing agent		m2		#N/A	$0.00	$0		$0	$0
Excavate and transport to offsite facility		m3		#N/A	$0.00	$0		$0	$0
Contour decontaminated area		m3		#N/A	$0.00	$0		$0	$0
CONTAMINATED SOIL VERY LOW PERMEABILITY COVER									
Supply geomembrame, HDPE, ES3, GCL		m2		#N/A	$0.00	$0		$0	$0
Upper and lower bedding layers		m3		#N/A	$0.00	$0		$0	$0
Install geomembrane, HDPE, ES3, GCL		m2		#N/A	$0.00	$0		$0	$0
Erosion protection layer		m3		#N/A	$0.00	$0		$0	$0
Vegetate		m2		#N/A	$0.00	$0		$0	$0
Install infiltration/seepage instrumentation		allow		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
OTHER									
				#N/A	$0.00	$0		$0	$0
					Total	$0		$0	$0
					% of Total			0%	0%

1 **Building / Equip Name:** **Bldg / Equip #:** ***1***

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost	% Land	Land Cost	Water Cost
DISPOSE MOBILE EQUIPMENT									
Decontaminate and ship off-site		allow		#N/A	$0.00	$0		$0	$0
Decontaminate and dispose on-site		allow		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
REMOVE BUILDINGS - see note below									
Accomodation Complex		m2		#N/A	$0.00	$0		$0	$0
Process Facilities		m2		#N/A	$0.00	$0		$0	$0
Offices, Repair, Lab, Warehouse		m2		#N/A	$0.00	$0		$0	$0
Storage Facilites		m2		#N/A	$0.00	$0		$0	$0
Water and Wastewater Treatment Facilities		m2		#N/A	$0.00	$0		$0	$0
U/G Heating Plant		m2		#N/A	$0.00	$0		$0	$0
Emulsion Plant		m2		#N/A	$0.00	$0		$0	$0
AN Storage Facility		m2		#N/A	$0.00	$0		$0	$0
Warehouse, Shops and Other		m2		#N/A	$0.00	$0		$0	$0
Storage Facility at Laydown/Airstrip		m2		#N/A	$0.00	$0		$0	$0
Fuel tanks		m2		#N/A	$0.00	$0		$0	$0
Fuel Tanks		m2		#N/A	$0.00	$0		$0	$0
Freshwater intake		m2		#N/A	$0.00	$0		$0	$0
Reclaim pumps		m2		#N/A	$0.00	$0		$0	$0
Outfall & Diffuser		m2		#N/A	$0.00	$0		$0	$0
Airstrip lighting, navigation, electrician		mandays		#N/A	$0.00	$0		$0	$0
Airstrip lighting, navigation, mechanical		mandays		#N/A	$0.00	$0		$0	$0
Break foundation slabs	total of all buildings	m2		#N/A	$0.00	$0		$0	$0
Consolidate & dump boneyard debris		m3		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
LANDFILL FOR DEMOLITION WASTE									
Place rock cover		m3		#N/A	$0.00	$0		$0	$0
Place soil cover		m3		#N/A	$0.00	$0		$0	$0
Vegetate		ha		#N/A	$0.00	$0		$0	$0
GRADE AND CONTOUR PADS									
Accomodation Complex		ha		#N/A	$0.00	$0		$0	$0
Process Facilities		ha		#N/A	$0.00	$0		$0	$0
Offices, Repair, Lab, Warehouse		ha		#N/A	$0.00	$0		$0	$0
Storage Facilites		ha		#N/A	$0.00	$0		$0	$0
Water and Wastewater Treatment Facilities		ha		#N/A	$0.00	$0		$0	$0
U/G Heating Plant		ha		#N/A	$0.00	$0		$0	$0
Emulsion Plant		ha		#N/A	$0.00	$0		$0	$0
Warehouse, Shops and Other		ha		#N/A	$0.00	$0		$0	$0
Place rock cover		m3		#N/A	$0.00	$0		$0	$0
Vegetate		ha		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
PUNCTURE LINED SUMPS									
Puncture liner and place soil cover		m3		#N/A	$0.00	$0		$0	$0
RECLAIM ROADS									
Remove culverts		each		#N/A	$0.00	$0		$0	$0
Remove bridges		each		#N/A	$0.00	$0		$0	$0
Scarify and install water breaks		ha		#N/A	$0.00	$0		$0	$0
Scarify airstriip		ha		#N/A	$0.00	$0		$0	$0
Scarify laydown areas		ha		#N/A	$0.00	$0		$0	$0
Vegetate		ha		#N/A	$0.00	$0		$0	$0
Other				#N/A	$0.00	$0		$0	$0
SPECIALIZED ITEMS									
Dispose of misc. debris and laydown area refuse				#N/A	$0.00	$0		$0	$0
					Total	$0		$0	$0
					% of Total			0%	0%

Note: Unit costs are based on 3m high, single storey building. Scale larger building areas accordingly. E.g. 10m high building multiply area by 3.3 (10/3)

1 **Capital Expenditures and Short Term Water Treatment identified in 'Instructions' worksheet**

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost
BREACH DYKE EMBANKMENT						
Remove fill		m3		#N/A	$0.00	$0
Contour water intake area		m3		#N/A	$0.00	$0
STABILIZE SEDIMENT PONDS/WATER MANAGEMENT PONDS						
Place soil cover		m3		#N/A	$0.00	$0
Doze & spread excavated material		m3		#N/A	$0.00	$0
Vegetate spread material		ha		#N/A	$0.00	$0
Rip rap in channel base		each		#N/A	$0.00	$0
REDIRECT RUNOFF/CONSTRUCT DIVERSION DITCHES						
Excavate ditches -soil		m3		#N/A	$0.00	$0
Excavate ditches -rock		m3		#N/A	$0.00	$0
Stabilize side slopes		m3		#N/A	$0.00	$0
Rip rap in channel base		m3		#N/A	$0.00	$0
BREACH DITCHES						
Excavate breaches		m3		#N/A	$0.00	$0
Backfill/recontour		m3		#N/A	$0.00	$0
Install flow dissipation		m3		#N/A	$0.00	$0
Vegetate remainder of ditch		m2		#N/A	$0.00	$0
DECOMISSION FRESH WATER SUPPLY						
Breach embankment		m		#N/A	$0.00	$0
Remove pump		LS		#N/A	$0.00	$0
Remove pipeline		m		#N/A	$0.00	$0
WATER CONTROL IN RECLAMATION QUARRY						
Install pumping system		LS		#N/A	$0.00	$0
Remove pumping system		LS		#N/A	$0.00	$0
REMOVE PIPELINES						
Remove pipes		m		#N/A	$0.00	$0
Concrete plug deep pipes		m3		#N/A	$0.00	$0
Other				#N/A	$0.00	$0
GROUNDWATER COLLECTION SYSTEM						
Excavate/install sumps		m3		#N/A	$0.00	$0
Install pumping wells		m3		#N/A	$0.00	$0
Install pumps/pipelines/power supply		LS		#N/A	$0.00	$0
CONSTRUCT CONTAMINATED WATER STORAGE POND						
Excavate pond		m3		#N/A	$0.00	$0
Doze & spread excavated material		m3		#N/A	$0.00	$0
Vegetate spread material		ha		#N/A	$0.00	$0
Bedding layer		m3		#N/A	$0.00	$0
Supply geomembrane		m2		#N/A	$0.00	$0
Install geomembrane		m2		#N/A	$0.00	$0
Erosion protection layer		m3		#N/A	$0.00	$0
CONSTRUCT PASSIVE TREATMENT SYSTEM (e.g. Constructed Wetland)						
Construct access roads		km		#N/A	$0.00	$0
Install HDPE piping system from collection pond		m		#N/A	$0.00	$0
Inter-cell flow structures		allow		#N/A	$0.00	$0
Install liners		m2		#N/A	$0.00	$0
Install growth media		m3		#N/A	$0.00	$0
Wetland vegetation		ha		#N/A	$0.00	$0
CONSTRUCT WATER TREATMENT PLANT						
Build treatment plant		LS		#N/A	$0.00	$0
Build sludge containment facility		LS		#N/A	$0.00	$0
SHORT TERM WATER TREATMENT*						
Annual water treatment cost, from "Water Treatment"						$0
					Total	$0

*Note: include water treatment cost from "Water Treatment" worksheet if treatment is considered short term and is not included in a particular component worksheet.

1 **Water Treatment**

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost
ADDITION OF REAGENTS						
H2O2		kg		#N/A	$0.00	$0
lime		kg		#N/A	$0.00	$0
ferric sulphate		kg		#N/A	$0.00	$0
ferrous sulphate		kg		#N/A	$0.00	$0
flocculents		kg		#N/A	$0.00	$0
Other				#N/A	$0.00	$0
LABOUR AND SUPPLIES						
Annual fuel		litres		#N/A	$0.00	$0
Annual power		kW-h		#N/A	$0.00	$0
Electrician/mechanic to maintain treatment plant		allow		#N/A	$0.00	$0
Equipment maintenance and parts		allow		#N/A	$0.00	$0
Misc. supplies, hoses, tools		allow		#N/A	$0.00	$0
Communications		allow		#N/A	$0.00	$0
Other				#N/A	$0.00	$0
WATER SAMPLING AND ANALYSES						
Sampling equipment		allow		#N/A	$0.00	$0
Analyses		allow		#N/A	$0.00	$0
Shipping to laboratory		allow		#N/A	$0.00	$0
Reporting		allow		#N/A	$0.00	$0
Other				#N/A	$0.00	$0
SITE ACCESS						
Road maintenance (incl. snow removal)		allow		#N/A	$0.00	$0
Winter road tariff		allow		#N/A	$0.00	$0
Truck rental		allow		#N/A	$0.00	$0
Air support		allow		#N/A	$0.00	$0
					Annual water treatment costs	$0
Number of years of water treatment		years				
					Total	$0

Note: Short term water treattment is intended to be included in "Water Management", whereas long term, or post-closure, water treatment is inc
"Post-Closure Monitoring and Maintenance"

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1 Post-Closure Monitoring & Maintenance:

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost
MONITORING & INSPECTIONS						
Annual geotechnical inspection		each		#N/A	$0.00	$0
Survey inspection		each		#N/A	$0.00	$0
Regulatory costs*		each		#N/A	$0.00	$0
Site water monitoring (AEMP and SNP)		each		#N/A	$0.00	$0
- Active closure and flooding		each		#N/A	$0.00	$0
- Post pit flooding		each		#N/A	$0.00	$0
Air Quality Monitoring Program (AQMP)		each		#N/A	$0.00	$0
Wildlife Effects Monitoring Program (WEMP)		each		#N/A	$0.00	$0
Vegetation Monitoring		each		#N/A	$0.00	$0
Other				#N/A	$0.00	$0
COVER MAINTENANCE						
Repair erosion - infill gullies		allow		#N/A	$0.00	$0
Repair erosion - upgrade diversion ditches		allow		#N/A	$0.00	$0
Remove problem vegetation		allow		#N/A	$0.00	$0
Repair animal damage		allow		#N/A	$0.00	$0
Repair/upgrade access controls		allow		#N/A	$0.00	$0
Other				#N/A	$0.00	$0
SPILLWAY MAINTENANCE						
Repair erosion		m3		#N/A	$0.00	$0
Clear spillway		each		#N/A	$0.00	$0
CWTS MAINTENANCE						
Maintain flow, restore vegetation		allow		#N/A	$0.00	$0
POST-CLOSURE WATER TREATMENT**						
Annual water treatment cost, from "Water Treatment"						$0
Subtotal, Annual post-closure costs						$0
Discount rate for calculation of net present value of post-closure cost, %				0.00%		
Number of years of post-closure activity					years	
Present Value of payment stream						$0

*Regulatory costs - annual reporting, management plans, progress reports etc

Include water treatment cost from "Water Treatment" worksheet if treatment is considered long term, such as ARD/ML.

1 **Interim Care and Maintenance**

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost
INTERIM CARE & MAINTENANCE						
on-site caretaker		manmonths		#N/A	0	$0
extra personnel		manmonths		#N/A	0	$0
-electrician		manmonths		#N/A	0	$0
-mechanic		manmonths		#N/A	0	$0
annual fuel		litre		#N/A	0	$0
misc. supplies		allow		#N/A	0	$0
pick-up truck		each		#N/A	0	$0
small dozer		allow		#N/A	0	$0
small excavator		allow		#N/A	0	$0
snow machine		allow		#N/A	0	$0
communications		allow		#N/A	0	$0
SNP/AEMP water sampling & reporting		each		#N/A	0	$0
geotechnical assessment		each		#N/A	0	$0
interim water treatment				#N/A		$0
other		each		#N/A	0	$0
			Annual	Interim C&M Cost		$0
Number of years of ICM		years			**Total**	$0

1 Mobilization/Demobilization:

ACTIVITY/MATERIAL	Notes	Units	Quantity	Cost Code	Unit Cost	Cost
MOBILIZE HEAVY EQUIPMENT						
Excavators		each		#N/A	0	$0
Dump trucks		each		#N/A	0	$0
Dozers		each		#N/A	0	$0
Demolition shears		each		#N/A	0	$0
Crane		each		#N/A	0	$0
Loader		each		#N/A	0	$0
Compactor		each		#N/A	0	$0
Light duty vehicles		each		#N/A	0	$0
MOBILIZE MISC. EQUIPMENT						
Pump shipping		each		#N/A	0	$0
Pipe shipping		m		#N/A	0	$0
Minor tools and equipment		allow		#N/A	0	$0
Truck tires		allow		#N/A	0	$0
Other				#N/A	0	$0
MOBILIZE CAMP						
Reclamation activities		allow		#N/A	0	$0
Long term reclamation activities (eg pump flooding)		allow		#N/A	0	$0
MOBILIZE WORKERS						
Reclamation activities - transport		each		#N/A	0	$0
Reclamation activities - travel time		manhours		#N/A	0	$0
Long term reclamation activities (eg pump flooding) - transport		each		#N/A	0	$0
Long term reclamation activities (eg pump flooding) - travel time		each		#N/A	0	$0
Monitoring Airfare		each		#N/A	0	$0
WORKER ACCOMODATIONS						
Reclamation activities		manmonths		#N/A	0	$0
Long term reclamation activities (eg pump flooding)		manmonths		#N/A	0	$0
MOBILIZE FUEL						
Fuel freight - reclamation activities		litre		#N/A	0	$0
Fuel freight - long term reclamation activities		litre		#N/A	0	$0
Fuel freight accomodations		litre		#N/A	0	$0
WINTER ROAD						
Construction and operation		km		#N/A	0	$0
Limited winter use		km		#N/A	0	$0
Winter road tarriff		km		#N/A	0	$0
DEMOBILIZE HEAVY EQUIPMENT						
Excavators		km		#N/A	0	$0
Dump trucks		km		#N/A	0	$0
Dozers		km		#N/A	0	$0
Demolition shears		km		#N/A	0	$0
Crane		km		#N/A	0	$0
Loader		km		#N/A	0	$0
Compactor		each		#N/A	0	$0
Light duty vehicles		km		#N/A	0	$0
Other		km		#N/A	0	$0
DEMOBILIZE CAMP						
		allow		#N/A	0	$0
DEMOBILIZE WORKERS						
crew travel time		mandays		#N/A	0	$0
crew transportation		each		#N/A	0	$0
WINTER ROAD						
Construction and operation		km		#N/A	0	$0
Limited winter use		km		#N/A	0	$0
Winter road tarriff		km		#N/A	0	$0
					Total	**$0**

Unit Cost Table (for refining unit costs see "Estimator" worksheet)

Filter by unit

ITEM	Detail	COST CODE	UNITS	LOW $	HIGH $	SPECIFIED $	COMMENTS
Accomodation							
		ACCM	manday	100.00	175.00		
Buildings - Decontaminate							
	Asbestos	BDA	m2	25.60	51.20		Low: removal of asbestos siding & flooring; High: removal of insulated pipes,
Buildings - Remove							Unit costs are based on 3m high, single storey building. Scale areas accordi
	Wood	BRW	m2	27.50	41.00		
	Concrete	BRC	m2	40.00	65.00	6.00	Specified: puncture concrete foundation slabs
	Steel - teardown	BRS1	m2	45.00	65.00		
	Steel - for salvage	BRS2	m2	67.00	100.00		
Concrete work							
	Small pour	CSF	m3	426.50	639.75		Low: YK; High=1.5xLow
	Large pour	CLF	m3	353.50	530.25	2,130.00	Specified: concrete crown pillar
Contaminated Soils							
	ESA Phase 1	CS1	each	7500.00			Low: small, "clean" site
	ESA Phase 1	CS2	each	50000.00			Low: small, "clean" site
	Remediate on site	CSR	m3	47.00	146.00		
Dozing							
	doze rock piles	DR	m3	1.05	2.40		Low cost: doze crest off dump
	doze overburden/soil piles	DS	m3	0.95	3.80		High cost: push up to 300 m
Excavate Rock; Low Spec's and QA/QC							
	drill/blast/load/short haul	RB1	m3	11.40	17.05		Low:quarry operations for bulk fill
	drill/blast/load/long haul	RB2	m3	12.05	17.80		
	RB1 + spread and compact	RB3	m3	12.05	17.80		
	RB2 + spread and compact	RB4	m3	12.50	30.75		
	Specified activity	RBS	m3				
Excavate Rock; High Spec's and QA/QC							(e.g. ditch/spillway excavation)
	drill/blast/load/short haul	RC1	m3	12.05	17.80		Low:foundation excavation;High:spillway excavation
	drill/blast/load/long haul	RC2	m3	12.70	18.40		
	RC1 + spread and compact	RC3	m3	12.70	18.40		e,g, cover construction
	RC2 + spread and compact	RC4	m3	13.50	19.20		e,g, cover construction
	Specified activity	RCS	m3			175.00	Specified-drift excavation
Excavate Rip Rap							
	drill/blast/load/short haul/place	RR1	m3	13.50	17.75		High: quarry & place rip rap in channel
	drill/blast/load/long haul/place	RR2	m3	14.20	20.65		
	source is waste dump/short haul	RR3	m3	7.00			cost includes sorting
	source is waste dump/long haul	RR4	m3	7.60			
	Specified activity	RRS	m3				
Excavate Soil; Low Spec's and QA/QC							
	clear & grub	SBC	m2	3.40	5.00		
	excavate/load/short haul	SB1	m3	4.30	5.90		
	excavate/load/long haul	SB2	m3	4.60	7.30		
	SB1 + spread and compact	SB3	m3	5.10	8.90		Low: non-engineered; High:engineered
	SB2 + spread and compact	SB4	m3	5.50	11.00		Low: non-engineered; High:engineered
	Specified activity	SBS	m3	3.20	6.30		Low: rehandle waste rock dump by dozing; High:rehandle waste rock by haul
	Tailings	SBT	m3	1.35	3.70	15.50	High:contour surface - wet or frozen; Specified:haul/place wet infill
Excavate Soil, High Spec's and QA/QC							
	excavate/load/short haul	SC1	m3	6.80	9.30		
	excavate/load/long haul	SC2	m3	7.10	11.75		
	SC1 + spread and compact	SC3	m3	8.90	14.20		Low: non-engineered; High:engineered
	SC2 + spread and compact	SC4	m3	9.30	23.20		Low: non-engineered; High:engineered (e.g. complex covers, low volume da
	Specified activity	SCS	m3			18.80	Backfill adit with waste rock
Fence							
		FNC	m	13.55	203.00		
Fuel and Electricity							
	Fuel cost - gas	FCG	litre	1.05	1.40		
	Fuel cost - diesel	FCD	litre	0.99	1.39		
	Fuel mobilization	FCM	litre	0.22	0.42		High: winter road usage
	Electricity	FCE	kW-h	0.17	0.19	0.49	Low and High:Yellowknife; Specified:diesel generator
Geo-Synthetics							
	geotextile	GST	m2	3.44			Supply and install

Unit Cost Table (for refining unit costs see "Estimator" worksheet)

Filter by unit

geogrid	GSG	m2	5.75		
liner, HDPE	GSHDPE	m2	7.95		Supply and install; large quantity
liner, ES3	GSES3	m2	20.20		FOB Yellowknife
geosynthetic installation	GSI	m2	3.16	14.00	Low:geotextile; High:ES3 or HDPE
bentonite soil ammendment	GSBA	tonne	308.30	348.50	FOB Edmonton, add shipping & mixing
Grouting (/m3 of rock grouted)					
	grout	m3	236.55	286.75	High: cement, FOB Yellowknife
Labour & Equipment Rates					
Site manager	sman	$/hr	125.00	152.00	
Supervisor	super	$/hr	52.00	91.84	
Registered engineer	eng	$/hr	95.00	220.00	
Environmental coordinator	envco	$/hr	74.16	130.00	
Evironmental technologist	envtech	$/hr	36.00		
Electrician	elec	$/hr	74.00	95.00	
Journeyman - various	journey	$/hr	44.00	71.79	
Labour - skilled	lab-s	$/hr	41.00	49.60	
Labour - unskilled	lab-us	$/hr	31.00	43.98	
Equipment operator	oper	$/hr	41.00	65.00	
Heavy duty mechanic	mech	$/hr	49.00	72.85	
Water treatment plant operator	oper-wt	$/hr	41.00	59.86	
Security / first aid	safety	$/hr	36.00	66.97	
Administative staff	admin	$/hr	38.00	57.89	
Equipment rates include operator and fuel					
Loader - 4 cu.yd (3.06m3)	load-s	$/hr	175.00		
Loader - 7 cu.yd (5.35m3)	load-l	$/hr	315.00		
Excavator - 26.76-30.84 tonnes	exc-s	$/hr	190.00		
Excavator - 68.95+tonnes	exc-l	$/hr	420.00		
Grader	grad	$/hr	190.00		
Dump truck off hwy 30-50 tonnes	truck-s	$/hr	225.00		
Dump truck off hwy 55-75 tonnes	truck-l	$/hr	300.00		
dozer, small	dozers	$/hr	205.00	260.00	
dozer, large	dozerl	$/hr	490.00	565.00	
smooth drum compactor	comp	$/hr	155.00		
scooptram, 6 yd3 bucket	scoop	$/hr	170.00		
flat bed truck with hiab	hiab	$/hr	155.00		
fuel truck	ftruck	$/hr	150.00		
water truck	wtruck	$/hr	58.00	150.00	
Mobilize Heavy Equipment					
Road access	MHER	kmtonne	3.40	10.25	
Air access	MHEA	kmtonne	12.00		cargo rate>500lb
Mobilize Camp					
Road access	MCR	each	50000.00		refurbish existing camp
Mobilize Workers					
flight	MW	each	4500.00	9100.00	Low:e.g. 8 passenger; High: Dash 7
Oil Removal					
oil removal	OR	litre	0.43	1.20	Low:waste oil heater; High: ship offsite
PCB Removal					
Remove from site	PCBR	litre	40.20	46.90	Low: shipping, handling & disposal from Yellowknife
Pipes, small (<6in dia.)					
remove/dispose on site	PSR	m	1.00	24.00	Low: remove/dispose on site; High: remove/re-use
supply	PSS	m	6.10	11.10	Low:supply; High:supply and ship
install	PSI	m	25.00		
Pipes, large (>6in dia.)					
remove/dispose on site	PLR	m	22.00	72.00	Low: remove/dispose on site; High: remove/re-use
supply	PLS	m	129.00	143.00	Low:supply; High:supply and ship
install	PLI	m	50.00		
Power Lines					
remove/dispose on site	POWR	m	25.50		
Process Chemicals					
Remove from site	PCR	kg	0.45	2.50	Low: shipping, handling & disposal from Yellowknife
Pumps					
Pump capital cost	PC	each	########		

Unit Cost Table (for refining unit costs see "Estimator" worksheet)

Filter by unit

Pump shipping	PS	each	2500.00			
Pump operating cost	POC	m3	0.12			pump operating costs should be calculated based on pump capacity, fuel cos
Pump maintenance	PM	allow	25000.00			
Pump sand BackFill						
	PBF	m3	85.00	300.00		
Scarify - road/mine site						
	SCFY	ha	4300	6030	2150	
Shaft, Raise & Portal Closures						
Shaft & Raises	SR	m2	645.00	2132.00		Low:pre-cast concrete slabs, little site prep. Area=shaft+>1m all around
Portals	POR	m3	18.80	250.00	1200.00	Low:unit cost code SCS;High:excavate & backfill collapsed portal;Spec: insta
Site Inspection Report						
	RPT	each	10000.00	20000.00		
SpillWay - Clear						
	SW	each	3000.00	7000.00		
Survey/Instrumentation						
	SI	each	1800.00	3600.00		2 person crew
Treatment Plant - Construct						
Small (< 1000 m3/d)	TPS	lump sum	9000000	15000000		
Large (> 1000 m3/d)	TPL	lump sum	15000000	46000000		
Constructed Wetland	CWTS	ha	200000	300000		
Treatment Plant - Operate						
	TPO	m3	0.35	2.00		
Treatment Chemicals						
ferric sulphate	ferric	kg	1.19			
ferrous sulphate	ferrous	kg	1.32			
lime	lime	kg	0.56			
hydrogen peroxide, 35%	hperox	kg	1.50			
Sodium Metabisulfate	Nametab	kg	1.18			
Caustic soda, 50%	caustic	kg	0.74			
Sulfuric acid, 93%	sulfuric	kg	0.31			
flocculant	flocc	kg	6.00			
copper sulphate	copper	kg				
shipping	shipping	kg	0.20			
Vegetation						
Hydroseed, Flat	VHF	ha	4000.00			
Hydroseed, Sloped	VHS	ha	4500.00			
Veg. blanket/erosion mat	VB	ha	13000.00			
Tree planting	VT	ha	2600.00	6000.00		
Wetland species	VW	ha			47.72	Specified= /m3, Wetland Growth Media Substrate mixed and installed (sand,
Water Sampling/Analysis/Reporting						
	WS	each	7000.00	10000.00		
Winter Road						
Construction	WRC	km	2000.00	11500.00		
Usage	WRU	kmtonne	0.29			

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Unit Cost Estimator

1 Equipment Productivity Figures and Graphs have been reproduced from Caterpillar Performance Handbook - Edition 42

EXCAVATION

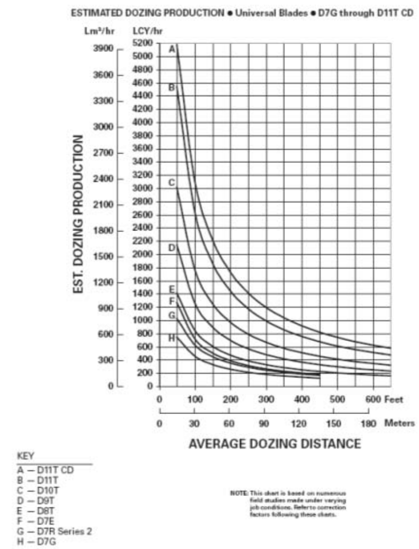
Productivity		
Machine Cat 336EL		
bucket capacity	3.16	m3
fill factor	75%	%
cycle time	45	seconds
operator skill	80%	%
machine availability	83%	%
altitude adjustment	100%	%
Hourly productivity	125.89	m3/hr
Operating Costs		
- Contractor		
Contractor hourly rate	$180.00	$/hr
Excavation cost - contractor rate	1.43	$/m3
- Owner		
ownership, daily		$/day
maintenance		$/hr
fuel		$/hr
consumables (cutters, tires)		$/hr
operator		$/hr
Owner hourly rate	$0.00	$/hr
Excavation cost - owner rate	$0.00	$/m3
Excavation cost - select contractor or owner rate (D22 or D31)		$/m3

HAUL AND DUMPING

Productivity		
Machine Cat 770		
truck capacity	25.1	m3
fill factor	80%	%
load time	6.0	min.
haul distance	1.5	km
average velocity	20.0	km/hr
haul time + return time	9.0	min.
wait time	0.5	min.
dump time	1.0	min.
cycle time	16.5	min.
machine availability	83%	%
altitude adjustment	100%	%
	13.7	ve. min/cycle
Hourly productivity	88.0	m3/hr
Operating Costs		
- Contractor		
Contractor hourly rate	$225.00	$/hr
Haul and Dump - contractor rate	2.56	$/m3
- Owner		
ownership, daily		$/day
maintenance		$/hr
fuel		$/hr
consumables (cutters, tires)		$/hr
operator		$/hr
Owner hourly rate	$0.00	$/hr
Haul/Dumping Cost - owner rate	$0.00	$/m3
Haul/Dumping Cost - select contractor or owner rate (I22 or I31		$/m3

SPREADING/DOZING

Productivity		
Machine Cat D8		
Estimate production using example curves provided or equivalent from other supplier	600	m3/hr
Correction factors (see table provided)		
operator skill	0.75	
material type, see table	0.80	
slot dozing	1.00	
side by side dozing	1.00	
visibility	1.00	
job efficiency	0.83	
altitude adjustment	1.00	
slope adjustment	1.00	
Hourly productivity	298.8	m3/hr
Operating Costs		
- Contractor		
Hourly rate - contractor supplied	$260.00	$/hr
Dozing - contractor rate	0.87	$/m3
- Owner		
ownership, daily		$/day
maintenance		$/hr
fuel		$/hr
consumables (cutters, tires)		$/hr
operator		$/hr
Owner hourly rate	$0.00	
Spreading/Dozing Cost - owner rate	$0.00	$/hr
Spreading/Dozing Cost - select contractor or owner rate (N22 or N31)		$/m3



Excavator

	Cat 320	Cat 325B	Cat 375
heaped bucket capacity, m3	1.5	2.2	5.4
	Typical Cycle Times (seconds)		
easy digging, shallow digging, small swing angle	16	18	20
med. to hard digging, rocky soil, swing angle to 90 deg.	23	23	25
tough digging, sandstone, caliche, at max. machine depth, swing angle > 120 deg.	27	29	35

Material	Fill Factor (% of heaped bucket capacity
Moist loam or sandy clay	100 - 110
sand and gravel (not till)	95 - 110
hard tough clay	80 - 90
rock - will blasted	60 - 75
rock - poorly blasted	40 -60

Operator Skill	poor	average	good
Correction factor	0.6	0.75	1

Machine availability	poor	average	good
Correction factor	0.9	0.95	1

Trucking

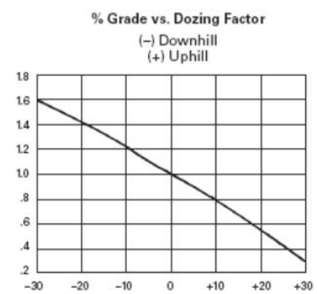
	Cat 771 D	Cat 777D	Cat 789C
Truck capacity - heaped, m3	27.5	60.5	137

Dozing

JOB CONDITION CORRECTION FACTORS

	TRACK-TYPE TRACTOR
OPERATOR —	
Excellent	1.00
Average	0.75
Poor	0.60
MATERIAL —	
Loose stockpile	1.20
Hard to cut; frozen —	
with tilt cylinder	0.80
without tilt cylinder	0.70
Hard to drift; "dead" (dry, non-cohesive material) or very sticky material	0.80
Rock, ripped or blasted	0.60-0.80
SLOT DOZING	1.20
SIDE BY SIDE DOZING	1.15-1.25
VISIBILITY —	
Dust, rain, snow, fog or darkness	0.80
JOB EFFICIENCY —	
50 min/hr	0.83
40 min/hr	0.67
BULLDOZER*	
Adjust based on SAE capacity relative to the base blade used in the Estimated Dozing Production graphs.	
GRADES — See following graph.	

*NOTE: Angling blades and cushion blades are not considered production dozing tools. Depending on job conditions, the A-blade and C-blade will average 50-75% of straight blade production.



APPENDIX B

RECLAIM MODEL USER MANUAL VERSION 7.0 (MAY 2014)

RECLAIM 7.0

USER MANUAL

Prepared for: Aboriginal Affairs and Northern Development Canada - Water Resources Division

Prepared by: Brodie Consulting Ltd.
March, 2014

This manual supports the RECLAIM 7.0 Model for Reclamation and Closure Security Estimates

RECLAIM Version 7.0 – March 2014
USER MANUAL

Table of Contents

1 Introduction

Reclaim has been updated by Brodie Consulting Ltd. (BCL) on behalf of Aboriginal Affairs and Northern Development Canada – Water Resources Division (AANDC) to assist AANDC and other stakeholders (typically mine proponents) to estimate reclamation costs at existing or new mine sites in the Northwest Territories and Yukon. The model format should also help these parties to better comprehend the multiple components of mine site reclamation liability.

It cannot be over-emphasized that in order to derive an accurate reclamation cost estimate it is imperative to have a closure plan that demonstrates a comprehensive understanding of the closure objectives and scope of work. The first step to using the model effectively is to prepare a comprehensive mine closure plan with sufficient detail to list and quantify the activities required.

This manual includes description of:

- Considerations for reclamation cost estimates in northern settings,
- How different parties may approach the cost estimate for a given site. An understanding of the perspectives may help resolve differences in the cost estimates.
- The RECLAIM model, and guidance on how to use it.

2 Considerations for Reclamation Cost Estimates in Northern Settings

Some factors that should be recognized when developing a reclamation plan and cost estimate for a site in northern Canada are discussed below:

- Low unit costs typically apply to work that is conducted in large volumes using appropriate equipment. However, in northern Canada efforts to reduce mobilization costs to remote sites may result in some work being conducted with non-optimal equipment.
- Some activities are best conducted in summer, such as placement and compaction of soils, while others may require winter (i.e. frozen) conditions for trafficability reasons. As such, reclamation activities may need to be extended over several seasons at some northern sites.
- Productivity of men and equipment is reduced in winter conditions.
- Fuel costs can be high, particularly as mobilizing fuel to site can contribute significantly.

3 Internal Estimate vs. Security Estimate

It is important to note that the cost estimate which a corporation may prepare and submit in support of its proposal for providing reclamation security is different than an owner's estimate prepared for internal use and will typically be higher. The differences are mainly in perspective, as outlined below.

<u>Owner's Estimate – Internal Use</u>
An owner's estimate for internal use present the costs which the corporation expects to incur as part of the development project. The estimates may be derived to assess the viability of the mine or for corporate cash flow accounting.

- Low unit costs are generally utilized as it is assumed that the work will be conducted under the direction of the mine manager utilizing existing staff and equipment.
- Equipment productivity may be assumed to be relatively high due to familiarity with working conditions on the site.
- Salvage and sale of used equipment might be applied to off-set demolition costs.
- A low contingency may also be applied based upon the assumption of the mine development and closure activities proceeding as planned without upsets or deviations.

<u>Owner's Estimate – Bonding Purpose/Regulator's Estimate</u>
The estimate which a corporation may prepare and submit in support of its proposal for providing reclamation security is expected to be similar to that which would be derived by a regulator. A regulator's estimate represents the government's expectation of costs should the company abandon the site.

- Unit costs are based upon third-party contractors conducting all of the work.
- Mobilization costs are included for every piece of equipment or machine required for the work (i.e. does not assume that existing mine equipment is available and in good working condition).
- No allowance for salvage value.
- Progressive reclamation is encouraged but until completed is included in the cost associated with closure and reclamation activities.
- Includes a provision for interim site care and maintenance to address the period of time between the ceasing of operations and the commencement of closure work.
- The contingency applied should address the degree of uncertainty in the closure plan, i.e. address key areas of uncertainty in closure options until such time as the preferred option is demonstrated or verified during the life of the project.

4 RECLAIM - General Description

RECLAIM is basically a tool to aid in the calculation and presentation of "quantity" of work multiplied by "unit cost" to carry out that work. For example, a reclamation activity may involve using a dozer to contour overburden in a disturbed area. If the quantity of soil to be dozed is 500 m^3 and the unit cost is $1.05/$m^3$, then the cost for that reclamation activity would be $525. RECLAIM is designed to assist the user in compiling this type of calculation for all reclamation activities for a mine site.

4.1 Worksheets

There are eleven reclamation costing tables, each on a separate worksheet, that are used to compute the overall cost of reclaiming a mine site.

The eleven worksheets are:

- Open pit
- Underground mine
- Tailings impoundment
- Rock pile
- Buildings and equipment
- Chemicals, hazardous materials, and contaminated soils
- Water management and short term water treatment
- Post-closure water treatment
- Interim care and maintenance
- Post-closure monitoring and maintenance
- Mobilization and demobilization

RECLAIM lists many typical reclamation activities for each component. These default lists will likely cover the majority of reclamation activities required for decommissioning a given mine. The default lists do not attempt to include all possible reclamation activities as the spreadsheet would be cumbersome. If a desired activity is missing from the default list the user may modify text within this area of the spreadsheet. Some of the default activities will not be applicable to the user's study, thus providing potential spaces to be overwritten by new reclamation activities.

Most of the worksheets for individual components are expected to be self-explanatory based on the list of activities for a given closure objective. However, the following worksheets are considered to warrant a description of the intent of the closure objectives.

4.1.1 Chemicals, Hazardous Materials & Contaminated Soil

This worksheet is intended to itemize the costs to inventory, collect (i.e. physically gathering materials from various locations around the mine site), and contain chemicals, hazardous material and contaminated soil for treatment or transport. Costs of offsite disposal fees at a certified facility are factored here. This component of the reclamation cost is often under-estimated or over-looked entirely.

Even the best managed mines will have minor problems with hydrocarbon contamination associated with fuel handling and storage of waste oil, lubricants, coolants, and hydraulic fluid. In addition, many base-metal mines have soil contamination in the ore concentrate areas, especially if these are not protected from wind. It is common at older mines to encounter problems with asbestos and PCB’s.

Management of any of these problems must be addressed on an individual basis, typically involving off-site site disposal. Some mines produce a significant volume of special or hazardous waste, which may require a hazardous waste landfill to be developed onsite.

This typically requires a sophisticated design to ensure that the wastes remain encapsulated in the long-term. Some hydrocarbon contaminated soil can be remediated on site.

4.1.2 Buildings and Equipment

This worksheet outlines the demolition costs for buildings typically found at a mine site assuming inert debris will be disposed of on site in an approved location such as a waste rock pile, landfill or other approved area specifically designated to accept these types of waste materials.

The area of each building is typically scaled to an average 3m high level. For example, the total square footage of a 6m building would be the area of the footprint of the building multiplied by two. Unit costs are then applied per m^2 as opposed to mandays such that the completion of demolition can be readily quantified and the reclamation liability released as completed.

Effort for disposal and burial of demolition waste needs to be included on this worksheet.

4.1.3 Water Management and Short Term Water Treatment

This worksheet provides a list of activities associated with water management; in essence the closure objectives for collection, control, or restoration of surface or groundwater flows. Capital costs of water treatment systems, i.e. water treatment plant or constructed wetland treatment system, are listed. In addition, there is a line included for short term, or defined duration water treatment calculated in the worksheet “Water Treatment”. An example might include treatment of a sediment pond with flocculent prior to release of water.

Alternatively, short term water treatment costs may be included within a component worksheet. For example, pit flooding activities such as batch treatment are listed within the worksheet “Open Pit”; costs of detoxifying a heap leach facility are listed within the “Rock Pile” worksheet; and treatment of tailings supernatant where reagents such as cyanide or ammonia are expected to decay to non-toxic levels in a specified period of time are included in “Tailings”.

Long term, or post-closure, water treatment for acid rock drainage or chronic metal leaching is costed in the worksheet “Water Treatment” but included in the worksheet “Post-closure Monitoring and Maintenance”.

For a list of how short term and long term (i.e. post-closure) water related activities are considered within RECLAIM refer to the following Table 1.

Table 1. Short Term Versus Long Term Water Management and Treatment

		Short Term	Long term
Open Pit	flood pit - install/operate pumping system	x	
	construct diversion ditches	x	
	treat 1st filling	x	
	install pump/decant system	x	
	passive/biological treatment	x	
	overflow treatment		x
Rock Pile/Heap Leach Facility	construct diversion ditches	x	
	install groundwater collection system	x	
	install toe seepage collection system	x	
	collect and treat groundwater		x
	collect and treat seepage (ARD/ML)		x
	install passive treatment system	x	
	operate and maintain passive treatment system		x
	detoxify heap leach pile (cyanide destruction)	x	
Tailings Facility	construct diversion ditches	x	
	pump supernatant (to pit, U/G)	x	
	treat supernatant	x	
	install toe seepage collection system	x	
	collect and treat seepage (ARD/ML)		x
	install passive treatment system	x	
	operate and maintain passive treatment system		x
U/G Mine	accelerate flooding	x	
	install seepage collection system	x	
	install dewatering/pumping system	x	
	operate seepage/dewatering system (ARD/ML)		x
Water Management	refill lakes		
	redirect creeks/streams	x	
	stabilize water management ponds	x	
	stabilize/close sediment ponds	x	
	fresh water supply - breach embankment	x	
	fresh water supply - remove piping system	x	
	construct water treatment plant	x	
	construct sludge pond	x	
	water control in reclamation quarry	x	
	operate/maintain water treatment plant		x

4.1.4 Water Treatment

This worksheet does not appear directly within the summary sheet. It is used to feed into either the "Water Management" worksheet when costs are for short term water treatment or the cumulative "Post-closure Monitoring and Maintenance" when costs are for long-term or post-closure water treatment such as ARD or chronic metal leaching. Costs to operate a water treatment plant are estimated within this worksheet.

4.1.5 Post-Closure Monitoring and Maintenance

Ideally, post-closure activity is a modification of the environmental and geotechnical monitoring program required during operation, along with infrequent maintenance. Commonly, the monitoring is conducted on a declining frequency at progressively fewer sampling points after closure. In many cases, the operational monitoring protocol will be expanded to address factors such as re-establishment of vegetation, metal up-take in vegetation or site specific stability concerns such as crown pillars.

Post-closure maintenance is often required, not in lieu of closure measures, but to compliment them. For example, spillways and diversions may require occasional clearing of debris and ice, rip rap may need to be repaired, covers over mine waste may require management of vegetation or repair of erosion. In most cases, post-closure maintenance will be a minor addition to the reclamation cost, mostly because this work will be infrequent.

In the case of very long time periods (e.g. 20+ years post-closure), a discount factor of 2.5 to 3% (also called the "real rate of return") may be applied when calculating the net present value of the future series of annual payments. This is appropriate provided that the future costs are estimated on the basis of current (or end of mine life) as opposed to nominal (inflated) costs.

The determination of the future series of costs will include all parameters, including: site access, monitoring, labour, fuel, and all reagents and supplies. It is recognized that the calculation of the net present value of a future series of costs can be complicated by a varying future frequency, typically a declining frequency, and that supporting worksheets/calculations may be required (not included in RECLAIM).

4.1.6 Interim Care and Maintenance

Very few mines commence closure work the day after operations cease. Although some mines re-open after closure, most mines remain in a state of care and maintenance for several years. This may be caused by the company approaching insolvency later in the operating life, or, an extended period of care and maintenance may result in a company becoming insolvent. In the case of abandoned mines, which reclamation security is intended to address, care and maintenance may occur for several years. Care and maintenance costs should include personnel, fuel, assorted supplies, and water treatment reagents. Permit requirements for environmental and geotechnical monitoring will have to be met during this period.

4.1.7 Mobilization/Demobilization

Mobilization/Demobilization of Equipment
The cost of supplying and removing equipment from a site will be an additional cost to the work. Based on third-party contractor based costs, this should be included for every piece of equipment or machine required for the work.

Personnel Movement & Accommodation
It is increasingly common for mines to be "fly-in and fly-out" sites. Consequently, at the time of closure, the costs for personnel movement and on-site accommodation will continue into the reclamation period.

4.1.8 Salvage and Progressive Reclamation

Salvage
Regulators in NWT do not recognize salvage value because of the problems associated with creditor's rights, sale of equipment, and uncertainty as to the actual value.

Progressive Reclamation
In most cases, mine reclamation cost estimates are prepared assuming that progressive reclamation is not conducted. It is recognized that this is financially punitive to the company. However, until this work is completed it is still an outstanding liability just like any reclamation which is put off until final closure of the mine. Therefore, financial security should be established to ensure that this work is conducted as proposed. If the company carries out progressive reclamation as proposed, such as revegetation of disturbed areas during operations, then the company's actual costs are likely to be lower than in the security provision and that portion could be returned when the company demonstrates that the closure activity has been completed.

4.2 Unit Cost Table

After having developed a comprehensive closure plan from which the reclamation activities have been scoped and quantified, the selection of Unit Costs is required to accurately cost each of the activities.

The unit cost table contains a list of many of the common reclamation activities that may be carried out at a particular mine site and the associated unit costs for each activity. To the extent achievable, all of the unit costs in the table have been based on actual reclamation work carried out at northern mine sites.

For each activity in the unit cost table, there is a brief description of the activity and a one to four-character acronym, called the cost code, for that activity. Additional activities, with user-defined cost codes and unit costs, may be added to the unit cost table.

To assist the user in remembering the acronyms, all descriptive text is shown in lower case except for those letters used to derive the acronyms. For example, if a reclamation activity such as covering a waste rock pile for re-vegetation involves the excavation of soil which is readily excavated and hauled a short distance and dumped, then the cost code SB1L would be appropriate. This acronym translates roughly as Soil, Bulk, 1 (for short haul), and low cost. The letter L in this acronym is a suffix which indicates that the cost for this particular activity is believed to be at the lower end of the range for soil movement. Factors such as an uphill haul, difficult excavation due to density, frozen zones or excessive boulders would require the use of the high cost suffix (H). If the excavation involved careful or controlled work, such as in ditch or spillway construction, then the SC1L cost code for Soil, Controlled, 1 (for short haul) and low cost may be more appropriate. In this way the selection of the cost code allows others to understand the assumptions of the estimator for the scope of work and intended effort.

4.3 Estimator

In some cases, rather than selecting a unit cost from the table, it may be appropriate to derive a specific unit cost from one of the following three methods:

- Quotes from qualified 3rd party contractors,
- Information provided by equipment suppliers, and,
- First principles.

Qualified Contractors

It is important to be very clear in obtaining costs from contractors. The contractor's cost should include mob/demob, capital cost, fuel, tires, maintenance, support equipment, and an operators hourly rate. Ideally, the contractor should have knowledge of local conditions and how they may vary with seasons. The more information the contractor has regarding the scope of work and conditions, the more reliable will be the cost estimate to carry out the work.

Equipment Suppliers

Unit cost data can be obtained from equipment suppliers. However, caution is warranted as a supplier is likely to provide only peak or optimal performance data. In most cases, adjustments will be required to reflect local cost factors such as labour rate and availability, or specific job site factors which affect productivity (cycle-times), weather, maintenance, down-time, and fuel consumption.

First Principle Cost Estimating

First principle cost estimating means evaluating equipment productivity in terms of hourly production divided by hourly cost of operation. Productivity evaluation is a series of adjustments or corrections to the peak or optimal productivity rate for a given piece of equipment. For example, adjustment factors for an excavator would involve difficultly in digging (type and hardness of material), job geometry (side-hill or full bench), finish condition (ditch versus quarry operation), operator skill (fair, good, excellent), working time per hour and other appropriate site factors.

Caterpillar Performance Handbook provides good methods of estimating productivity. Other sources of unit cost data are the RS Means Cost Works heavy construction data and Western Mine Engineering – Mining Equipment Costs.

4.4 Summary Sheet

The summary sheet presents the subtotals of capital and indirect costs to derive a total reclamation cost estimate. The direct costs of: Open Pit, Underground Mine, Tailings Facility, Rock Pile, Buildings and Equipment, Chemicals and Contaminated Soil Management, Surface and Groundwater Management, and Interim Care and Maintenance are derived from the individual worksheets as are the indirect costs Mob/Demob and Post-closure Monitoring and Maintenance. The portion of indirect costs to assign to "land liability" and "water liability" are calculated from the percentage of the direct costs that the land and water make up. These percentages are then applied to all of the indirect costs.

In addition to the indirect costs of mob/demob and post-closure monitoring and maintenance, there are a number of indirect costs that are calculated as a percentage of the direct costs. These are described below.

4.4.1 Engineering & Project Management

As assumption made in RECLAIM is that in the event of early closure due to company bankruptcy there is an existing, approved closure plan that can be converted to contract ready documents for closure activities, i.e. there are no dramatic departures from the approved reclamation and closure plan.

It will be necessary to provide engineering services in order to progress from the reclamation plan into a scope of work which can be provided to a contractor. Further engineering will be required while the work is being carried out to address unexpected problems and provide input to quality control such as material monitoring or survey.

Projects will also require general management and administration. As it is difficult to anticipate or scope the cost of engineering and project management, a provision of 5% to 10% of the direct project cost is included.

4.4.2 Bonding, Taxes, and Insurance

RECLAIM provides lines to enter values for these costs where appropriate.

4.4.3 Contingency

A contingency is added to the estimated cost to provide an allowance for uncertainty in the mine plan, required reclamation activities and scope, and actual unit costs at closure. Even if there is a high degree of certainty on the scope and effort of the anticipated reclamation work, a contingency is still required. Note that there is commonly considerable debate between owners and regulators about what is an appropriate contingency percentage.

It should be recognized that most reclamation security estimates are prepared early in the mine life. The degree of detail in the closure plan is relatively low. Consequently, a low contingency at this stage is not justified. Assuming diligent efforts by the company during the mine life, it is expected that the contingency would decrease.

Another way to evaluate what is an appropriate contingency is to critically assess the quality of the reclamation plan. It is suggested that a low contingency would be indicative of a plan based on a comprehensive database of site specific parameters, detailed engineering, and proven reclamation measures. In this regard, the latter point; "proven reclamation measures" is often key. Proven reclamation measures means that completed progressive reclamation activities on site have been shown to be effective and the effort and cost associated with that work is well understood.

Some guidance in the selection of an appropriate contingency factor can be found in the following Table 2. Virtually all reclamation plans and associated cost estimates are at the "feasibility or advanced conceptual" stage until possibly the last few years of the mine life.

In some cases, it may be appropriate to consider a different level of contingency for different components of the site reclamation.

Table 2. Selection of Appropriate Contingency for Security Estimate

Estimate Type	Description	Accuracy or appropriate contingency
Detailed or Project Control	Based upon detailed engineering take-offs and written quotes	+/- 5 %
Definitive or construction drawing phase	Engineering mostly complete, some written quotes	+/-10 %
Preliminary or budget level	Little detailed engineering and costs based upon verbal quotes	+/- 15 %
Feasibility or advanced conceptual	Engineering may be 10 % complete and costs based upon typical unit costs	+/- 20 %
Pre-feasibility, conceptual or trade-off study	Very basic engineering only and costs based upon typical unit costs	+/- 25 %

4.4.4 Market Price Factor Adjustment

There may be times when economic activity is very high, such that products and services are in high demand, resulting in elevated costs. This occurred in 2004 to 2008 in Northern Canada. Rather than use increased unit costs, a percentage can be applied to the direct costs to account for the higher contract costs expected.

5 Using Reclaim

Upon opening Reclaim, depending on the users security settings, the user may receive a SECURITY WARNING “macros have been disabled”. Select the “Enable this content” within the options menu. A pop up box will request the project name. Typically this is the mine name, which will inserted at the top right of each worksheet. The program will then initialize, which should only take a few seconds.

The program should open to the instructions sheet, which is an overview description of the program and details of program limitations. There are some requirements that must be met for the program to work. The following instructions should be reviewed prior to modifying the worksheets:

- The names of the worksheets must not be changed.
- Certain cells have defined names, which must not be changed. Where the cell is named, the name will appear in the name box.
- The first line of data for any component worksheet starts on line 4. Do not change the first line of a component worksheet.
- Cell A1 of the component sheet must always contain the “count” of that component for the duplicate function to work.
- The user can add lines to component activities and the unit cost table. However, the user should check that the unit cost does not fall outside the named ranges. You can check the size of the named range by selecting the name from the drop down box at the top left of the sheet. For example, in this version of reclaim the unit costs range is to line 175 of the unit cost worksheet.
- A component will only be printed if its sub-total is greater than zero. In addition, a component and the summary sheet cannot be printed if there is an error. Printing has been set to print 1 page per worksheet.

6 Completing Worksheets

The next step is to complete each of the individual worksheets by selecting the type of activity required, estimating the quantity (i.e. volume, area, length etc.) in column E and assigning an appropriate unit cost in column F. Activities are based on the mine closure and reclamation plan. The worksheets serve as a checklist of activities that may be required for the closure objectives to be met.

Activity items can be added to component worksheets, either by changing the activity/material description in column B or adding the activity where the line item is purposely left as “other”. When adding unit costs to the list, it is best to do this by replacing a unit cost that will not be used as there is a defined range for the associated name (see Section 5 above regarding unit cost named ranges).

7 Menu Descriptions

Functions specific to the Reclaim program are displayed in the tab “Add Ins” on the Excel menu bar. If this menu tab is not displayed, the functions are also found within the sheet titled “Tools”. A summary of the functions is provided in the Instructions worksheet and are described below:

<u>Clear</u>
This function deletes all input data, deletes any duplicated elements and blanks out the project name.

Another function within this menu is to hide or display segregation columns within the worksheets that ascribe the costs to either ‘water’ or ‘land” liability.

This function is useful after an operator has updated the Unit Cost table and wishes to use the new data for another project. Note the Clear function does not affect the unit cost table.

<u>Duplicate</u>
This function duplicates components of the project. For example, if there is more than one Open Pit, complete the activities and quantities for one Open Pit then use duplicate to add a second Open Pit. Quantities for the new Open Pit are erased, but the Activities and Cost Codes are carried over from the original Open Pit. The new Open Pit subtotal is added to the Summary page. The duplicate function can be applied for the following worksheets: open pit, underground mine, tailings impoundment, rock piles, buildings and infrastructure, and estimator.

<u>Unit Costs</u>

By selecting the show/hide function within unit costs a window of unit costs is displayed to the right of the open worksheet to allow the user to view the table of unit costs for ease of reference. The unit cost table has a filter in the 'UNITS' column. You can select to only see a particular unit (e.g. km) or multiple units (km and m^3) or all units.

By selecting the inflate function, unit costs can be increased by a percentage to account for inflation from the date the unit costs were last updated (Version 7.0 updated March 2014).

<u>Print All</u>
This option prints the Summary Worksheet, Unit Cost Worksheet, and individual component worksheets having non-zero balances. Individual worksheets can be printed directly using standard printing methods.

CANADIAN PROVINCIAL REPORT—ONTARIO

1. Background and History

1.1 Mineral Resources

The Province of Ontario is a leading producer of metals such as platinum, nickel, cobalt, gold, copper, silver and zinc. To date, the total value of all metal production in Ontario is estimated at $450 billion Canadian dollars (CDN). Diamonds and salt are also mined in the province. 460 million ounces of cobalt have been mined out of the province since 1903. An estimated 175 million ounces of gold have been mined from northern Ontario since gold was first discovered in the province in 1866. In 2012, the Lac de Iles Mine produced over 2.7 million ounces of palladium and 218,224 ounces of platinum along with smaller amounts of gold, copper, and nickel (Ministry of Northern Development and Mines; MNDM 2103). Over 13,600 cubic meters of granite were extracted from four producers in Vermillion Bay and several major diamond exploration projects occurred in northwest Ontario in 2013 (MNDM 2103).

Salt deposits in Ontario are found in the Windsor and Sarnia-Goderich areas near the eastern edge of the Michigan Basin, and form an extension of the Michigan salt deposits. They were first discovered in 1866. These salt formations are found at depths of 275 to 825 metres and range in thickness from 90 to over 200 meters.

1.2 Petroleum Resources

Ontario commercial oil producers are an integral part of the Ontario economy, supplying energy through historical and modern methods and refining oil in since the 1860s. In 2013, commercial producers generated 439,000 barrels of oil with a value of $38.3 million CDN. This oil was extracted from 1,183 wells including 717 historical oil fields. After 165 years of production, approximately 50 percent of the potentially recoverable oil and gas remains to be developed.

More recently, Ontario commercial natural gas producers have supplied natural gas to distributors in southwestern Ontario since the early 1900s. In 2012, commercial producers generated 6.5 billion cubic feet of natural gas with a value of $22.1 million CDN. This gas was extracted from 1,221 wells.

Southwestern Ontario is the center of natural gas distribution with one of North America’s largest underground natural gas storage hubs, located in Dawn-Euphemia Township. (Ontario Petroleum Institute 2014)

2. Regulatory Structure

2.1 Regulatory Agencies

2.1.1 Mining Sector

MNDM regulates mining, mineral exploration, and development via the Ontario Mining Act. The Voluntary Rehabilitation of Mine Hazard Regulation under the Act removes legal barriers for voluntary rehabilitation of abandoned mine sites on Crown land. These provisions removed certain environmental liabilities for companies who voluntarily rehabilitate mine hazards on Crown lands.

2.1.2 Petroleum Sector

The Ontario oil and natural gas industry is regulated by the Government of Ontario's Ministry of Natural Resources and Forestry (MNRF). Via the Ontario Oil, Gas, and Salt Resources Act, Regulation 245/97 and the Provincial Operating Standards, the MNRF oversees the safe extraction of Ontario's natural resources (Ontario (MNRF 2014).

2.1.3 Water and Land Resources

The Ministry of Environment and Climate Change (MOECC) is responsible for issuing approvals for water use and release of pollutants to the air, water, or land. These approvals affect both the mining and petroleum sectors. Water use approvals have specific security requirements, to ensure water resources are restored by the approval holder once those water resources are no longer needed. For this reason, the security requirements associated with water use approvals is discussed in brief in this report.

2.2 Statutory and Regulatory Framework

2.2.1 Mining Sector

The Ontario Mining Act (Chapter M-14) forms the statutory basis for mining activities in the province of Ontario. There are two regulations relevant to dismantlement, reclamation, and remediation (DR&R) activities in Ontario: Voluntary Rehabilitation of Mine Hazards Regulation and the Mine Development and Closure Regulation.

2.2.2 Petroleum Sector

The Oil, Gas, and Salt Resources Act (Chapter P-12) forms the basis for the regulation of petroleum and petroleum related resources in Ontario. The Exploration, Drilling, and Production Regulation enumerate the security requirements associated with oil and gas activities.

2.2.3 Water and Land Resources

Section 132 to 136 of the Ontario Environmental Protection Act (Chapter E-19) establishes financial assurance requirements for orders or approvals under the Act and the Ontario Water Resources Act. Section 89 of the Ontario Water Resources Act allows the MOECC to use the security deposit posted in conformance with the Ontario Environmental Protection Act to recover costs.

Part XV.1 of the Ontario Environmental Protection Act establishes the basis for the MOECC to issue a Record of Site Condition. Section 168.6(1) of the Act authorizes the Director of Environment to take action as specified in the certificate of property use that is deemed necessary to prevent, eliminate, or ameliorate any adverse effects identified in the risk assessment performed for the property. The Act also establishes authorization for the MOECC to issue approvals and emissions to the environment, including to the air, water, and noise emissions. It also establishes approvals for waste processing, management, and disposal activities for other types of contaminated sites.

Both mining and petroleum operators must obtain approvals from the MOECC under the Ontario Water Resources Act. Additionally, these operators must meet the security requirements under the Ontario Environmental Protection Act and at the same time, comply with the security requirements under the Ontario Mining Act and the Oil, Gas, and Salt Resources Act.

3. Security/Financial Assurance Requirements

In order to ensure that the rehabilitation work outlined in a closure plan is successfully performed, even if the party responsible for DR&R activities faces financial or legal troubles, a financial guarantee equal to the estimated cost of the rehabilitation work must be held in trust by the Ministry of Finance. This financial guarantee is known as financial assurance. Financial assurance must be included with the submission of a closure plan.

Financial assurance will be returned to the party responsible for DR&R activities at the end of the rehabilitation work activities. Financial assurance will only be returned if the rehabilitation work is performed in accordance with the closure plan and either meets the satisfaction of the MNDM requirements in the case of mines or the MNR in the case of petroleum related activities following an inspection of the site.

3.1 Calculation of Financial Assurance Amounts

3.1.1 Mining Sector

The Mine Rehabilitate Code of the Mining Development and Closure Regulations requires financial assurance to be submitted with a mine closure plan at the onset of mine permitting. The statutory basis for security requirements is the Ontario Mining Act, Part VII. This statute and affiliated regulations ensure that a mining company meets its reclamation and remediation requirements even if the mining company becomes insolvent. These regulations mitigate the province liability for costs. After mining activities have ceased and the mining closure plan has been completed, inspected, and approved by the MNDM, part or all of financial assurance will be returned.

A cost estimate and estimated value of financial assurance required must be submitted in the closure plan along with a description of how the financial assurance value was derived. For the corporate financial test option, which is considered a soft form of financial assurance, the mine operator must meet or exceed two of the credit ratings issued by the credit rating service organizations described in Table 3.1-1 (Section 16, Mine Rehabilitation Code). This demonstrates that it can meet its DR&R obligations for the entire life of the mine. If the credit rating is downgraded during the closure activities, it must notify the MNDM and provide the financial security in the amount it has identified in its closure plan.

Table 3.1-1 Minimum Corporate Financial Test Ratings Required for Financial Assurance for Full Life of Mine

Approved Credit Rating Service[1]	Minimum Rating		
	Rating	**Description**	**Scale Reference**
Dominion Bond Rating Service Limited 2013	A (low)	**Good Credit Quality** The capacity for the payment of financial obligations is substantial, but of lesser credit quality than AA. May be vulnerable to future events, but qualifying negative factors are considered manageable.	Long-Term Obligations Rating Scale
Moody's Investor Services Inc. 2014	A3	Upper-medium grade and are subject to low credit risk. Modifier 3 indicates a ranking in the lower end of that generic rating category.	Long-Term Rating Scale
Standard & Poor's Inc. (S&P) 2014	A-	**Investment Grade** Obliger has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. Minus (-) sign shows relative standing within the major rating categories.	Long-Term Issuer Credit Ratings

Notes:

1 Mine Closure Guidelines Financial Assurance, written in 2001, cites the Canadian Bond Rating Service, Inc. as an approved credit rating service; however, this rating service company was purchased by S&P The Canadian Bond Rating Service Ratings have been harmonized with the S&P ratings.

The mine operator has the option to use the corporate financial test to demonstrate financial assurance for the first half of a mine's life with a lower rating classification as long as it meets two of the ratings described in Table 3.1-2 (Section 17, Mine Rehabilitation Code). This option is only available for mines where the first half life of the mine is four years. If the mine's credit rating drops below the ratings in Table 3.1-2, it must notify the Minister and provide the financial security in the amount specified in its Closure Plan. Allowing for the use the corporate financial test for demonstrating financial assurance option for the first half of the mine's life provides flexibility for mine operators who have a lower rating while still allowing the regulators a level of assurance that DR&R costs will be borne by the operator.

Table 3.1-2 Minimum Corporate Financial Test Ratings Required for Financial Assurance First Half of Mine Life

Approved Credit Rating Service[1]	Minimum Rating		
	Rating	Description	Scale Reference
Dominion Bond Rating Service Limited 2013	BBB (low)	**Adequate Credit Quality** The capacity for the payment of financial obligations is considered acceptable. May be vulnerable to future events.	Long-Term Obligations Rating Scale
Moody's Investor Services Inc. 2014	Baa3	Medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. Modifier 3 indicates a ranking in the lower end of that generic rating category.	Long-Term Rating Scale
Standard & Poor's Inc. 2014	BBB-1	Considered lowest investment grade by market participants	Long-Term Issuer Credit Ratings

Notes:

1 Mine Closure Guidelines Financial Assurance, written in 2001, cites the Canadian Bond Rating Service, Inc. as an approved credit rating service; however, this rating service company was purchased by S&P The Canadian Bond Rating Service Ratings have been harmonized with the S&P ratings.

3.1.2 Petroleum Sector

3.1.2.1 New and Existing Wells

The Oil, Gas, and Sand Resource Act require every operator of a well to establish security in the following amounts. Well security required for each operator is:

- $0 for each licensed oil well that is registered as part of an oil field having historical oil field status
- $0 for each private well
- $0 for each licensed hydrocarbon storage cavern well located on land as long as the operator owns both the surface rights and the mineral rights
- $3,000 for each unplugged well located on land drilled to less than 450 meters in depth
- $6,000 for each unplugged well located on land drilled to a depth greater than 450 meters but less than 800 meters

- $10,000 for each unplugged well located on land drilled to a depth greater than 800 meters
- $15,000 for each unplugged well located in water covered areas (Government of Ontario. 2004, Regulation 245/97, section 16.3; Regulation 22/00, section 5.3)

The maximum security required is:

- $70,000 for unplugged wells located on land
- $200,000 for unplugged wells located in water covered areas
- $70,000 for unplugged wells located on land
- $200,000 for unplugged wells located in water covered areas

3.1.3 Water and Land Resources

Financial assurance requirements associated with water use approvals or orders issued by the MOECC are described in Section 132(1) of the Ontario Environmental Protection Act. Financial assurance associated with certificates of property use issued by the MOECC can be found in Section 132(1.1) of the Act. Financial Assurance Guideline (Guideline F-15) establishes how to calculate the amount of security required for an approval issued by the MOECC under the Ontario Environmental Protection Act and the Ontario Water Resources Act. Section 6 of the Financial Assurance Guideline document describes the procedures for computing the amount of financial assurance for a variety of short-term and long-term cases. The MOECC uses the four year mark as the basis to differentiate between short-term (less than four years) and long-term planning horizons (four or more years). The guidance describes the types of costs to include in the estimate of financial assurance along with information concerning when costs can be discounted, and how to address inflation. A copy of the guidance document is provided as Appendix A to this report.

3.2 Acceptable Security Types

3.2.1 Mining Sector

The Government of Ontario accepts the following forms of security instruments as financial assurance to cover closure costs [Ontario Mining Act, Chapter M-14, RSO 1990, Part VII - Advanced Exploration and Mine Production, Financial Assurance, 145(1) and Ontario Environmental Protection Act, Chapter E-19, R.S.O. 1990131]:

- Cash
- A letter of credit from a bank named in Schedule I to the Bank Act (Canada)
- A bond of an insurer licensed under the Insurance Act to write surety and fidelity insurance

- A mining reclamation trust as defined in the Income Tax Act (Canada)
- Compliance with a corporate financial test in the prescribed manner
- Any other form of security or any other guarantee or protection, including a pledge of assets, a sinking fund or royalties per ton, that is acceptable to the Director

3.2.2 Petroleum Sector

For onshore oil and gas wells, the security must be in the form of a fund administered in accordance with the Trustee Act [Ontario Oil, Gas, and Salt Resources Act 16(1)(b)]. The trust fund must be on the following types of funds [Ontario Oil, Gas, and Salt Resources Act 16(1.1)]

- A bank to which the Bank Act (Canada) applies
- An insurance company, or a fraternal benefit society, to which the Insurance Companies Act (Canada) applies
- An association to which the Cooperative Credit Associations Act (Canada) applies
- A co-operative credit society incorporated by or under an Act of Ontario
- A trust, loan or insurance corporation incorporated by or under an Act of Ontario
- A brokerage firm incorporated or formed by or under an Act of Canada or of Ontario that is primarily engaged in dealing in securities, including portfolio management and investment counselling
- An accountant licensed under the Public Accountancy Act who carries at least $2,000,000 of professional liability insurance
- A lawyer qualified to practice in Ontario who carries at least $2,000,000 of professional liability insurance

3.2.3 Water and Land Resources

The MOECC accepts the following forms of financial assurance for water approvals or orders and for certificates of property use (Section 131 of Ontario Environmental Protection Act):

- Cash
- A letter of credit from a bank
- Negotiable securities issued or guaranteed by the Government of Ontario or the Government of Canada
- Personal bond accompanied by collateral security

- Bond of an insurer licensed under the Insurance Act to write surety and fidelity insurance
- Bond of a guarantor, other than an insurer, accompanied by collateral security;
- Agreement, in the form and terms specified in the approval, order or certificate of property use
- An agreement, in the form and terms prescribed by the regulations

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APPENDIX A

GOVERNMENT OF ONTARIO FINANCIAL ASSURANCE GUIDELINE (GUIDELINE F-15)

GUIDELINE F-15

Financial Assurance Guideline

Legislative Authority:
Environmental Protection Act, R.S.O. 1990, Part XII, Sections 131 to 136 and 176

Last Revision Date:
June 2011

PIBS 0226e04

Ontario

ACKNOWLEDGMENT

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Table of Contents

1. Introduction

For the Purposes of this Guideline, on and after the day subsection 2 (1) of Schedule 7 to the Open for Business Act, 2010 comes into force, a reference to an approval, a certificate of approval, an approval under section 9 of the Environmental Protection Act, an approval under Part V of the Environmental Protection Act or an approval under section 53 of the Ontario Water Resources Act shall be deemed, unless the context requires otherwise, to be a reference to an environmental compliance approval.

Please note that Regulatory Requirements have been included in this Guideline for convenience only. A copy of current legislation should be obtained and used in conjunction with the guideline. To access legislation please refer to Service Ontario's e-Laws site at www.e-laws.gov.on.ca/index.html or contact Service Ontario by telephone at 1-800-668-9938 (locally at 416-326-5300) or by e-mail at e-laws@ontario.ca.

Financial Assurance is authorized under Part XII of the *Environmental Protection Act* (EPA) and allows Program Directors to require, as a condition of an order (only in a Director's Order), approval or by regulation, the provision of financial security by regulated parties. Provincial Officers do not have the authority to require Financial Assurance as a condition of a Provincial Officer's Order. The regulated parties are defined as firms, persons or crown corporations.

Financial Assurance can be required either to:

- Ensure compliance with environmental objectives;
- Ensure that requirements are achieved by a specified deadline; or
- Ensure that funds are available for future clean-up and remediation of landfills and other contaminated sites which require long-term care and monitoring.

This Guideline has been prepared to help Ministry staff administer Financial Assurance under different circumstances and to help regulated parties and their advisors comply with requirements.

In this Guideline, the following appendices are provided:

a) Compliance Cost Items to Estimate the Amount of Financial Assurance Required for Specific Orders, Approvals, Facilities and Activities, Appendix A;

b) Ontario Legislation – Part XII, sections 131 to 136 and section 176 of the *Environmental Protection Act*. Legal authority to require Financial Assurance is derived from these sections, Appendix B;

c) Sections 1, 2, 17 and 18 of the Landfilling Sites Regulation (Ontario Regulation 232/98), Appendix C;

d) Sections 1 and 8 of the Mobile PCB Destruction Facilities Regulation (Regulation 352), Appendix D;

e) Templates for Standard Non-Cash Forms of Financial Assurance (Surety Bond and Irrevocable Letter of Credit), Appendix E;

f) Flow Charts Showing Financial Assurance Procedures and Responsibilities, Appendix F;

g) List of Planned Landfill Closures and Post-Closure Care Activities, Appendix G;

h) Spreadsheet Template for Calculating Financial Assurance Amounts for a Typical Landfill Site, According to Ontario Regulation 232/98, Appendix H;

i) Financial Assurance Refund/Disbursement Form, Appendix I;

j) Definitions, Appendix J; and

k) Procedures to Obtain Non-Residential Building Construction Price Index for Toronto (NRCPIT) from Statistics Canada Website, Appendix K.

For further information, call the Environmental Assessment and Approvals Branch or any Regional Office of the Ministry of the Environment, or visit the website at http://www.ene.gov.on.ca.

2. Legislative Authority

Legislative authority for the requirement of Financial Assurance is derived from Part XII (Financial Assurance), sections 131 to 136 and 176, of the *Environmental Protection Act* (EPA). Financial Assurance can be specified as conditions of orders and approvals that are issued under the EPA or the *Ontario Water Resources Act* (OWRA) or as required by regulation.

Orders and approvals should not refer to sections 35, 46 or 47 of the *Environmental Protection Act* as authority for Financial Assurance.

3. Statement of Principles

3.1 This Guideline specifies how Financial Assurance requirements are to be administered by the Ministry of the Environment.

3.2 Financial Assurance under Part XII of the EPA can be required as a condition of an order, an approval or a regulation.

3.3 Financial Assurance is required to ensure that funds are available for, but not limited to the following:

a) The performance of environmental measures specified in approvals, orders or regulations;

b) Decommissioning, clean-up, rehabilitation, monitoring and perpetual care of facilities such as private waste processing and disposal sites as well as other types of contaminated sites;

c) The operation and maintenance of private water or sewage treatment facilities until they can be assumed by a municipality;

d) Alternate water supplies may be required where the Director has reasonable grounds to believe that existing water supplies are, or are likely to be, contaminated or otherwise interfered with by the works to which the approval or order is related;

e) Compensation to third parties who incur damages due to polluting activities if such a condition is stated in the approval or order. Compensation is limited to areas where there is statutory authority; and

f) Various facilities identified in Sections 4.2, 4.3 and 4.4.

3.4 Financial Assurance may be required by a Program Director under the following circumstances:

a) Financial Assurance is compulsory in every case when stipulated by a regulation. As of June 2004, only two regulations require Financial Assurance:

i) Ontario Regulation 232/98 - Landfilling Sites

ii) Regulation 352 - Mobile PCB Destruction Facilities

b) For all other cases, Financial Assurance requirements are discretionary on the part of the Program Director.

i) Financial Assurance is normally required (i.e., usually required in every case) as a condition of orders or approvals that are listed in Section 4.3. However, if the Program Director exercises discretion in not requiring Financial Assurance, he/she must document reasons in the case file.

ii) With respect to orders and approvals listed in Section 4.4, Financial Assurance is <u>not</u> normally required however, the Program Director exercises discretion in whether Financial Assurance is required. The Program Director must document the reasons for requiring Financial Assurance in the case file. Financial Assurance should be required when one or more of the situations or conditions listed in Section 4.4 apply.

3.5 Although Part XII of the EPA was enacted in 1986, Financial Assurance can be applied as conditions in approvals that were issued before 1987 by amending the said approval. The Program Director must have valid reasons for doing so, such as a risk of financial liability to the Ministry exists if the regulated parties fail to meet the obligations of their orders or approvals by reason of bankruptcy or insolvency.

3.6 Financial Assurance can be applied to provide an incentive for regulated parties to implement compliance activities but it cannot be retained as a penalty. Financial Assurance must ultimately be used to pay for compliance actions or be returned to the regulated party.

3.7 Above all, Financial Assurance requirements should be:

a) <u>Sufficient</u> to pay for all of the potential costs associated with conditions in an order or approval; and

b) Easily <u>accessible</u> when the Ministry needs to use it.

3.8 This Guideline addresses the following topics:

a) Situations where Financial Assurance should be required of proponents who are subject to orders or approvals (Section 4);

b) The form in which Financial Assurance can be provided to the Ministry (Section 5);

c) How to determine the amount of Financial Assurance to be required (Section 6);

d) Procedures for issuing an order or approval with a Financial Assurance requirement and for accepting, receiving and handling Financial Assurance funds or documents (Section 7);

e) Criteria and procedures for converting non-cash Financial Assurance to cash and for using Financial Assurance to implement the terms and conditions in orders and approvals (for example, responses to defaults) (Section 8);

f) Criteria and procedures for returning Financial Assurance to regulated parties when it is no longer required (Section 8); and

g) Responsibilities carried out by Ministry staff (Section 9).

3.9 Financial Assurance will not normally be required of municipalities, other provincial ministries, and other public bodies or institutions for the following reasons:

a) These entities are not subject to bankruptcy and financial insolvency to the same degree as are private companies;

b) Municipalities have a permanency of place which prevent them from walking away from local problems; and

c) Public institutions are generally backed by provincial or federal government resources.

3.10 Municipal Corporations formed in accordance with section 203 of the *Municipal Act, 2001* must provide Financial Assurance until such time that the Municipal Corporation can satisfy the Ministry of the Environment that their Financial Assurance will be guaranteed by the municipality.

4. Rules and Conditions to Determine When Financial Assurance Should be Required

4.1 The flow chart presented in Appendix F illustrates the categories of Financial Assurance according to the degree of discretion. Financial Assurance is mandatory in every case when it is required by a regulation. Regulations that require Financial Assurance are detailed in Section 4.2.

Orders, approvals and other activities for which Financial Assurance is usually required in every case are detailed in Section 4.3.

Orders, approvals and other activities for which Financial Assurance is usually required where certain situations or conditions apply are detailed in Section 4.4.

In all other cases, Financial Assurance is discretionary.

4.2 Financial Assurance is required by the following regulations:

a) Ontario Regulation 232/98 - Landfilling Sites

b) Regulation 352 - Mobile PCB Destruction Facilities

4.2.1 In accordance with Ontario Regulation 232/98 - Landfilling Sites, Financial Assurance is mandatory for:

a) New private sector landfill sites intended to accept municipal (i.e., non-hazardous) waste that came into existence after August 1, 1998 and that were intended, at the time they came into existence, to have a total waste disposal volume of more than 40,000 cubic metres; and

b) Expanded private sector landfill sites in which:

i) the alteration, enlargement or extension was proposed after August 1, 1998,

ii) the total waste disposal volume would be increased to more than 40,000 cubic metres, and

iii) only municipal (i.e., non-hazardous) waste would be accepted.

4.2.2 In accordance with Regulation 352 - Mobile PCB Destruction Facilities, Financial Assurance is mandatory for:

a) Class 1 mobile PCB destruction facility waste disposal sites, and

b) Class 2 mobile PCB destruction facility waste management systems.

4.3 Financial Assurance should normally be required in an order or approval for the types of facilities listed in Sections 4.3.1 and 4.3.2. The reasons should be recorded in the case file if the Program Director exercises his/her discretion not to require Financial Assurance in any of these cases.

4.3.1 Approvals under Part V, EPA including but is not restricted to:

a) Private landfill sites not covered in Section 4.2.1. For example,

i) new private landfill sites which have a total waste disposal volume of 40,000 cubic metres or less;

ii) proposed expansion of private landfill site of a total waste disposal volume of 40,000 cubic metres or less; or

iii) existing private landfills in existence prior to August 1, 1998 either operating or closed, but are in the contaminating life span stage.

b) Private transfer stations, private waste processing sites (i.e., private recycling operations and private material recovery facilities). In addition, Financial Assurance is not normally required from private facilities which handle biosolids under the organic soil conditioning program and septic wastes;

c) Private waste management (haulage) systems which carry biomedical and PCB wastes;

d) Private used tire storage or disposal facilities which contain more than 5,000 tire units;

e) Incineration facilities including sites burning waste derived fuels (WDF).

4.3.2 Approvals under section 53, OWRA including:

a) Private communal sewage works in unorganized areas where there is no agreement with the Ministry of Municipal Affairs and Housing for a local government agency (for example, an area services board or a municipality to be created, or an existing municipality to be expanded) to take over the works in the event of a default;

b) Private communal sewage works in organized areas without an agreement with the local government agency to take over the system in a default situation.

4.3.3 Financial Assurance is not meant to take the place of an agreement with a municipal authority. At the time of initial approval, the Ministry will continue to require a municipality or, in an unorganized area, another governmental organization to enter into a responsibility agreement for the long-term operation and maintenance of communal sewage works and systems. However, Financial Assurance should be provided until such agreements are finalized. Furthermore, if the local agency or municipality has obtained Financial Assurance, there is no need for the Ministry to obtain Financial Assurance.

4.4 Financial Assurance should be required for facilities listed in Sections 4.4.1 to 4.4.5 if any of the following situations apply, which should be specified in the order or approval file as reason(s), including:

a) Where a required action, process or task could result in adverse effects, such as increased health or environmental risks, contamination of or interference with the operation and use of municipal or private wells, or hazards to public health and safety.

b) When the operation or waste residuals of a facility are judged to be high risk in that the release of a contaminant could cause health, environmental or property damage, including contamination of the operation or interference with the operation and use of a municipal or private well.

c) When a Ministry of the Environment official determines that a facility or operation will require future decommissioning, rehabilitation, site rededication or environmental clean-up measures and includes these requirements as conditions in an order or approval.

d) When future long-term or perpetual management or monitoring of an existing or potential pollution or contamination problem is required by an order or approval.

e) When there is reason to expect that the regulated party might become insolvent in the future and be unable to complete or comply with the terms and conditions of an order or approval.

f) When a regulated party or person has been convicted of violations involving pollution discharges or emissions for specific or related problems addressed in an order or approval.

g) When the regulated party has missed a deadline in any previous orders or approvals.

h) When the regulated party has received an extension to a compliance date in an order or approval.

i) Where any past or current activities of the regulated party have resulted in any documented occurrence of human health or environmental damage or have resulted in significant risk of human health or environmental damage.

4.4.1 Approvals under Part V, EPA including:

a) PCB storage sites established in accordance with written Director's instructions under Regulation 362 - Waste Management – PCBs;

b) Waste management systems (haulage) which handle any material except biomedical and PCB waste. The Financial Assurance requirements for biomedical and PCB waste are noted in Section 4.3.1, paragraph c). Finally, Financial Assurance is not normally required from haulers of biosolids (processed organic wastes and hauled sewage).

4.4.2 Approvals under section 53, OWRA including:

a) Private communal sewage systems and works;

b) Industrial and milling activities that generate tailings, ash or other waste materials subject to section 53, OWRA (but not facilities which provide Financial Assurance under the *Mining Act*);

c) Any sewage works in which waste materials that are generated by the sewage works, including sludges, are stored or disposed of on the site of the sewage works; and

d) Any sewage works, or any part thereof, that contain waste materials, such as sludges, that are to remain on the site after decommissioning.

4.4.3 Approvals under section 9, EPA including (but not limited to) those that contain conditions associated with:

a) Specific abatement actions that contain time deadlines;

b) Equipment and technologies for air pollution reduction;

c) The storage of subject waste materials from air pollution control equipment;

d) Equipment used in the mobile in-situ chemical oxidation process; and

e) Back-up control equipment.

4.4.4 Permits to take water under section 34, OWRA where there is the expectation of associated adverse effects on:

a) Other known users of the same surface or ground water supply source;

b) The environment, such as low flows in streams, etc.;

c) Surrounding properties which take water from the same ground water supply; and

d) Where potential rededication measures are likely required.

4.4.5 Orders including:

a) Industrial abatement programs under section 18, EPA;

b) An industrial or commercial site which is contaminated with hazardous materials and is to be decommissioned; and

c) Operations which store subject wastes on site under Regulation 347 - General – Waste Management, for more than 90 days.

5. Forms of Financial Assurance

5.1 The form of Financial Assurance to be provided is to be chosen by the Program Director based on consultation with other Ministry staff and the regulated party.

5.2 Forms of Financial Assurance which are acceptable are described in section 131 of the EPA. Definitions of financial terms are found in Appendix J.

5.3 The Business and Fiscal Planning Branch holds all original Financial Assurance forms as well as supporting documents for safekeeping.

5.4 There are three basic forms of Financial Assurance: Standard, Non-standard and Unacceptable. Forms can either be cash or non-cash within the classifications.

5.4.1 Standard forms of Financial Assurance are always acceptable and include:

a) Cash;

b) Irrevocable letters of credit;

c) Surety bonds; and

d) Negotiable securities issued by or guaranteed by provincial or federal government.

5.4.2 Non-standard forms are not generally recommended but may be accepted if a proponent makes a compelling case. Staff should request that the proposal be reviewed by Legal Services Branch, Business and Fiscal Planning Branch and Economic Analysis Section to determine whether the proposed form should be accepted. Non-standard forms include:

a) Any security or collateral accepted by the Program Director;

b) Agreements, contracts or other non-standard forms of Financial Assurance with conditions stated in the order or approval;

c) Insurance policies;

d) Guaranteed Investment Certificates (GICs) reissued payable to the Ontario Minister of Finance;

e) Marketable securities (apart from those mentioned above in Section 5.4.1) or other negotiable securities;

f) Indemnification Agreements;

g) Letters of guarantee; and

h) Qualified Environmental Trust accompanied by letter of credit, cash or bond. This form is an agreement made between two parties for the purpose of a tax benefit to the regulated party.

The *Condominium Act, 1998*, subsection 115 (5), defines an eligible security as “a bond, debenture, guaranteed investment certificate, deposit receipt, deposit note, certificate of deposit, term deposit or other similar instrument that,

- is issued or guaranteed by the government of Canada or the government of any province of Canada,
- is issued by an institution located in Ontario insured by the Canada Deposit Insurance Corporation, or
- is a security of a prescribed class.”

Apart from negotiable bonds and debentures, each of these forms are considered non-standard for purposes of Financial Assurance and staff should seek assistance and advice from Legal Services Branch, Business and Fiscal Planning Branch and the Economic Analysis Section before accepting them.

5.4.3 The following forms are unacceptable and should <u>not be accepted</u> by Ministry staff:

a) Guaranteed Investment Certificates (GICs) which are not transferable;

b) All bonds which are not transferable;

c) Bank accounts held by the regulated party or joint bank accounts held by the Ministry and the regulated party;

d) Insurance policies for long-term projects or landfill sites; and

e) Guarantees from out-of-province, off-shore firms.

5.4.4 Any form of Financial Assurance offered by a proponent that is not mentioned in Sections 5.4.1 or 5.4.2 should be considered unacceptable until reviewed and approved by Legal Services Branch, Business and Fiscal Planning Branch and/or the Economic Analysis Section. All unusual wording of standard forms (e.g., letters of credit or surety bonds) should always be reviewed by Legal Services Branch.

5.5 During the time that a non-standard form is being reviewed, a standard form of Financial Assurance (e.g., cash or a letter of credit) should be provided to the Ministry. If the non-standard form is approved by the Ministry, the standard form should be returned to the regulated party.

5.6 Where it is necessary to use Financial Assurance for clean-up or long-term care and maintenance activities in the future, a cash account is recommended. The advantages of a cash account are:

a) Cash is readily accessible to the Ministry;

b) Cash does not require interaction with other institutions to retrieve the funds;

c) Cash deposits do not require monitoring to ensure that the value is sufficient each year; and

d) Non-cash forms of Financial Assurance such as letters of credit, surety bonds and negotiable securities guaranteed by government will normally have to be monitored and increased annually in accordance with a cumulative Financial Assurance balance schedule stated as a condition in the order or approval.

5.7 Where marketable securities or other negotiable securities are accepted as Financial Assurance, the market value of these securities should be at least 20 per cent in excess of the agreed to amount of Financial Assurance in order to allow for fluctuations in the market prices of these securities.

5.8 Examples of wording for two standard forms of Financial Assurance, a surety bond and an irrevocable letter of credit, are presented in Appendix E.

5.9 Procedures by which Ministry staff should accept, process and handle Financial Assurance payments for all forms of Financial Assurance are described in Section 7.3; procedures for specific forms of Financial Assurance are described in Section 7.4 of this Guideline.

5.10 Regulations may be made from time to time to require particular forms or amounts of Financial Assurance in specific cases.

6. Computing the Amount of Financial Assurance

6.1 Procedures and information requirements to determine Financial Assurance

This Section presents steps, procedures, concepts and information requirements to determine amounts of Financial Assurance to be provided to the Ministry for various types of orders, approvals, activities, sites and facilities.

6.1.1 Sections 6.2, 6.3, and 6.4 specify activities and cost items that should be included to determine the amount of Financial Assurance required. Procedures to calculate Financial Assurance amounts consist of two broad approaches:

a) Procedures for projects where the planning period of an order or approval is less than four full years or when there is no known future date for closure, clean-up or remediation expenditures, are presented in Sections 6.5 and 6.6 (No discounting).

b) Procedures for projects where the planning period of an order or approval is four full years or longer, or when there is a known future date for closure, clean-up or remediation expenditures, are presented in Sections 6.7 and 6.8 (Discounting).

Section 6.9 provides further information regarding the use of Financial Assurance by owners or operators. Finally, Section 6.10 discusses conditions and procedures which might reduce the amount of Financial Assurance required by some regulated parties. Further information and guidance relevant to the computation of costs and Financial Assurance amounts may be found in Appendix A.

6.1.2 Procedures presented in this Guideline incorporate the requirements and procedures found in Ontario Regulation 232/98 - Landfilling Sites which generally applies to new or expanding sites after 1998 and Regulation 352 - Mobile PCB Destruction Facilities. Reference should be made to these regulations for definitive language.

6.1.3 Further information and guidance are provided in Appendix A: Compliance Cost Items to Estimate the Amount of Financial Assurance Required for Specific Orders, Approvals, Facilities and Activities, and Appendix G: List of Planned Landfill Closures and Post-Closure Care Activities. Appendix H presents an example of

Financial Assurance calculations for a typical landfill site based on the procedures required under Ontario Regulation 232/98.

6.2 Least-cost methods of compliance to satisfy conditions in orders or approvals may be used to determine Financial Assurance amounts

6.2.1 Where more than one method or technique exists to achieve the specified conditions, tasks, requirements or objectives in an order or approval, the amount of Financial Assurance required may be based on the least-cost option which is environmentally acceptable regardless of which method is actually chosen by the proponent. For example,

a) If a landfill is progressively closed and capped as each cell is filled, the amount of Financial Assurance for closure would only be required for the final active area of the site, not the entire site area. However, Financial Assurance for post-closure maintenance and monitoring should be based on the entire filled area of the site; and

b) If hazardous wastes must be cleaned up and removed from a site, these wastes can either be destroyed in a plasma arc furnace or sent to a licensed landfill for disposal. However, the least-cost disposal approach should be used for estimating the amount of Financial Assurance.

6.2.2 Although the regulated party is permitted to calculate Financial Assurance amounts based on the least-cost option to provide environmental protection, there may be technical or environmental reasons why a more expensive option should be applied at a particular site rather than the least-cost option. If a more expensive option is required, Ministry staff must provide written reasons for this requirement in the file.

6.2.3 Financial Assurance for all types of facilities must be updated periodically to reflect any changes in site conditions or requirements in the order or approval. For example, certificates of approval for landfills usually have a condition that requires Financial Assurance to be updated at least every three years or as otherwise specified by the Program Director.

6.3 Amounts of Financial Assurance are based on costs of activities to comply with conditions and requirements in an order, approval or regulation

6.3.1 Examples of compliance cost items include:

a) Costs of planned site closure, post-closure care and maintenance and potential contingency actions for privately owned landfills which are specified in Ontario Regulation 232/98 or in terms and conditions of an approval;

b) Capital and operating costs of abatement or prevention technologies and systems to reduce air or water pollution releases to comply with an order; and

c) One-time capital and annual operating costs of private water and sewage treatment works which do not have municipal commitments to take over operation of the facility.

6.3.2 Definitions of key terms are listed below. A glossary of other terms relevant to Financial Assurance is found in Appendix J.

a) Cost or a cost item may be a one-time (capital) expenditure or it may be a recurring annual operating expenditure.

b) One-time cost items refer to capital costs or consulting services which are incurred usually once during the planning period. One-time costs include the costs of equipment, installation of machinery and equipment, construction of buildings and other site improvements. Other one-time costs include contract services, architect services, design and engineering, construction or installation costs, laboratory testing, project management fees, etc.

c) Recurring costs refer to costs associated with the operation, maintenance and monitoring of equipment, buildings and the site, including the costs for labour, materials, ongoing consultant services, etc.

d) Contaminating life span of a landfill is the period of time, after closure, in years, from the expected year of closure until the site finally produces contaminants at concentrations that are below levels which have unacceptable health or environmental effects.

e) Operating period of a landfill is the period from the first day of operation until the day that the landfill site closes.

f) Planning period depends on the type of order or approval. Planning periods for a landfill consist of the time between the day the site starts receiving waste until the end of the contaminating life span. For waste processing or transfer facilities, the planning period extends from the day that the Ministry issues an approval for the facility until the day that the site has completed all required clean-up and remediation procedures. The planning period of an order to implement abatement projects, extends from the day that the Ministry issues an order until the day that all compliance actions are completed to the satisfaction of the Director.

g) Forms of Financial Assurance include standard, non-standard or unacceptable forms. Definitions and examples of the forms can be found in Appendix J. Financial Assurance may also be classified as either cash or non-cash forms. Forms are discussed in Section 5.

6.3.3 The amount of Financial Assurance should be based on the expected one-time and recurring costs of each compliance activity specified in relevant regulations or in specific orders or approvals over the intended planning period. For example,

a) The costs of cleaning up and disposing of residues from a potential spill and the rehabilitation of a potential spill site, if applicable;

b) The one-time costs of removal, hauling and disposal of all of the waste materials being generated, processed or stored at a site;

c) The estimated one-time (capital) costs and long-term recurring maintenance costs (including monitoring, treatment, storage or security) of decommissioning a contaminated site or facility;

d) Management, supervisory, administrative and any other similar costs. Normally, these costs are expressed as a percentage of one-time and/or recurring costs. Evidence or references to verify the percentage or an alternate estimation procedure used should be provided; and

e) Contingency costs are budgeted for uncertain or unknown events or occurrences that would force a facility or owner to incur unplanned costs. Contingencies may also refer to cost items that are known but have a low probability of being incurred.

   i) Contingency costs may be expressed as recurring or one-time costs for unexpected construction, operation, maintenance and replacement of works. Where explicit estimates are not available, contingency costs may be estimated as 10 to 15% of total one-time and recurring costs, by all regulated parties except for landfill sites. Contingency costs must be required in a condition in the approval or order.

   ii) For new or expanded landfill sites installed after 1998, the amount of Financial Assurance for contingencies shall be determined in accordance with the formula given in Ontario Regulation 232/98. For all other landfill sites, the amount of Financial Assurance for contingencies shall be determined by the Program Director on a case by case basis.

   iii) Where Financial Assurance for contingency costs has been provided in a non-cash form (e.g., letter of credit, surety bond), Ministry staff should review the conditions of the approval or order at the time that the landfill site is closed to determine if there are any reasons why the non-cash form should be converted to cash and deposited in the Consolidated Revenue Fund.

   iv) Financial Assurance for contingency costs may be used by the Program Director to pay expenses related to any planned or unplanned closure of the site or to the post-closure care of the site, if the owner fails, on direction from the Program Director, to perform the work to cover the expenses.

6.4 Financial Assurance Proposals

6.4.1 Financial Assurance Proposals contain written estimates of the capital, other one-time costs and annual recurring costs associated with each project, activity or facility for which Financial Assurance is required. The regulated party must provide this information with reference to Appendix A. The proposal should be mandated by a condition in an approval or an order.

6.4.2 Whether a new submission or an update of an existing Financial Assurance account, the Financial Assurance Proposal must include:

a) Facility specifications (as discussed in Table H1 in Appendix H) including, but not restricted to the:

   i) planning period over which Financial Assurance will be required. There are no predetermined minimum or maximum time periods for which Financial Assurance should be required;

   ii) first year of operation or commencement of project;

   iii) anticipated year of closure or project completion;

   iv) contaminating life span of a landfill (a minimum of 25 years);

   v) maximum allowable volume of waste on site, if a landfill;

   vi) volume of unprocessed and usable (processed) secondary materials on site of a transfer station or waste processing facility;

   vii) maximum allowable quantities of processed and unprocessed waste;

   viii) total area or footprint of site or facility and the area that Financial Assurance is being submitted for, if not the same as the total area; and

   ix) annual fill rates of a landfill.

b) Clear explanations of all sources of data and assumptions used in estimates and computations, include, but are not restricted to:

   i) a list of all compliance activities and conditions for which costs will be estimated;

   ii) unit or sized costs of different activities;

   iii) estimation procedures and steps;

   iv) references for all data sources;

   v) worked examples of all computations;

   vi) estimation error ranges (i.e., +/- %) for each cost item; and

vii) expected variations in recurring and capital costs over time.

c) The amount of Financial Assurance to be provided, the form it is to be provided in (e.g., cash, letter of credit, surety bond, etc.) and the dates that it is to be provided to the Ministry.

6.4.3 Where estimates of many cost items are provided in tables depicting long periods of time, regulated parties should provide tables electronically in spreadsheet formats (either Microsoft Excel or Corel Quattro Pro accepted) with all formulas accessible and active. Please refer to Appendix H for further details.

6.4.4 All data and estimates provided in the Financial Assurance Proposal will be reviewed to ensure:

a) Reasonableness;

b) Completeness, in that all activities and associated costs have been included in the submission to address the conditions or terms of an order or approval;

c) Appropriateness of financial parameters (inflation and discount rates); and

d) Accuracy of computations.

6.4.5 If a Financial Assurance Proposal with required cost estimates and proposed Financial Assurance amounts is not submitted with a new approval application, the application should be returned to the regulated party.

6.4.6 If an updated/revised Financial Assurance Proposal for an existing account is not submitted within the required time period, e.g., 3 to 5 years depending on the type of facility, Ministry staff may initiate appropriate enforcement actions to elicit submission of a new Financial Assurance Proposal.

6.4.7 If an existing operator refuses to provide a Financial Assurance Proposal and/or the required Financial Assurance amount as per an order or approval, Ministry staff must initiate appropriate enforcement actions.

6.5 Estimating Financial Assurance when the planning period is less than four years or when there is no known future date for closure, clean-up or remediation expenditures (No discounting)

6.5.1 The following types of activities and facilities from Section 4 would normally have planning periods of less than four years and/or the future date for closure, clean-up or remediation expenditures is not known:

a) Private transfer stations and private waste processing sites (Section 6.5.5);

b) Private waste management (haulage) systems which carry wastes (Section 6.5.6);

c) Private used tire storage or disposal facilities which contain more than 5,000 tire units (refer to Section 6.5.5 and A.3 in Appendix A);

d) Regulation 352 - Mobile PCB Destruction Facilities (Section 6.5.7);

e) PCB storage sites established in accordance with written Director's instructions under Regulation 362 - Waste Management – PCBs. The Financial Assurance procedures also apply to other waste materials stored on site (Section 6.5.8);

f) Approvals under section 53, OWRA including private communal sewage systems and sewage works in unorganized or organized areas without a municipal government agency agreement to take over the system (Section 6.5.9);

g) Approvals under section 9, EPA (Section 6.5.10);

h) Approvals for operations which discharge into surface waters subject to section 53, OWRA (Section 6.5.11);

i) Permits to take water under section 34, OWRA (Section 6.5.12);

j) Orders to undertake industrial abatement programs under section 18, EPA (Section 6.5.13);

k) Orders to require decommissioning and remediation of contaminated sites (Section 6.5.14); and

l) Orders involving storage of subject wastes under Regulation 347 (Section 6.5.15).

6.5.2 When computing Financial Assurance for these types of facilities and activities, costs required to comply with all conditions and requirements in an order or approval should not be discounted.

6.5.3 Financial Assurance for these types of activities or facilities may include contingency costs. Contingency costs may be explicit estimates of one-time or recurring cost elements or they can be estimates of between e.g., 10 to 15%. Reasons should be entered in the file if contingency costs are not required.

6.5.4 Upon request, Financial Assurance for these activities or cases may be returned or reduced dollar for dollar as the project is completed and the regulated party provides evidence that money has been spent and that part of the Financial Assurance is not required in respect of the works.

6.5.5 Private transfer stations and private waste processing sites (See also A.1 in Appendix A)

6.5.5.1 Financial Assurance to be provided for these facilities is equal to the total cost of removing, transporting and disposing of any materials left on site if the owners or operators cease operations for any reason and could not, or would not, clean up the site.

6.5.5.2 The amount of Financial Assurance required is equal to:

a) 100% of the cost of loading, hauling and disposing of all the material to a licensed disposal facility; plus

b) 100% of the cost of site remediation activities such as construction of a security fence if the site is abandoned; plus

c) Contingency cost = 10 to 15% of the total removal, disposal and remediation activities.

6.5.5.3 Financial Assurance for these facilities may be computed with the following formula:

$$FA = [(MW \times \%_1 \times UC_{1L}) + (MW \times \%_1 \times UC_{1H}) + (MW \times \%_1 \times UC_{1D}) + (MW \times \%_2 \times UC_{2L}) + (MW \times \%_2 \times UC_{2H}) + (MW \times \%_2 + UC_{2D}) + \ldots\ldots + (MW \times \%_n \times UC_{nL}) + (MW \times \%_n \times UC_{nH}) + (MW \times \%_n \times UC_{nD})] + [REM] + [CON]$$

where,

FA = Financial Assurance

MW = Maximum allowable waste for site

$\%_{1, 2, ..., n}$ = Per cent of different types of waste (1, 2, 3, ..., n) that may be subject to different costs

$UC_{nL, H, D}$ = Unit Cost of Loading, Hauling or Disposal for each type of waste, 1, 2, 3, ..., n

REM = Other remediation costs such as fences, building demolition

CON = Contingency costs or (Loading + Hauling + Disposal + REM costs) × (10...15% depending on uncertainty of other cost estimates)

6.5.5.4 If conditions in the certificate of approval require actions to prevent potential off-site contamination arising from operation of the site, the costs of these actions should be estimated. It would be prudent to obtain Financial Assurance for these actions until the owner provides evidence that the actions have been completed.

6.5.5.5 Financial Assurance for the above-noted cost items should be obtained by the Program Director before the commencement of operations or as otherwise required by the Program Director.

6.5.6 Private waste management (haulage) systems which carry wastes (See also A.2 in Appendix A)

6.5.6.1 Financial Assurance should be provided by haulers of biomedical and PCB wastes. Haulers of any other waste material which satisfy one or more of the criteria in Section 4.4 paragraph a) should also provide Financial Assurance in order to pay for potential costs such as the clean-up and disposal of contaminated soil or debris from a spill or fire. As per the *Guide for Applying for Approval of a Waste Management System*, which may be obtained from the Environmental Assessment and Approvals Branch of the Ministry of the Environment, a Financial Assurance amount of at least $50,000 is required for biomedical waste haulers and at least $100,000 is required for PCB haulers. The procedures and input data for arriving at these predetermined dollar amounts should be reviewed every five years by staff to assess sufficiency.

6.5.6.2 For haulers of any other material for which Financial Assurance may be required, the amount should be equal to 100% of the estimated costs of cleaning up, hauling away and disposing of debris and contaminated soil from a spill or upset involving the largest vehicle owned by the regulated party.

6.5.7 Regulation 352 - Mobile PCB Destruction Facilities (See also A.4 in Appendix A)

6.5.7.1 Mobile PCB destruction facilities with approvals under Regulation 352 should provide the following predetermined amounts of Financial Assurance:

a) $50,000 for each Class 1 mobile PCB destruction facility waste disposal site, and

b) $50,000 for each Class 2 mobile PCB destruction facility waste management system (hauler).

The procedure for arriving at these predetermined amounts should be reviewed every five years by staff to assess sufficiency. These amounts may be adjusted from time to time.

6.5.8 PCB storage sites established in accordance with written Director's instructions under Regulation 362 - Waste Management – PCBs

6.5.8.1 Financial Assurance for PCB storage facilities should equal 100% of the total one-time capital costs of removing the total allowable capacity of the PCBs to a licensed destruction facility plus the charges for destroying all of the PCBs in the facility.

6.5.8.2 The procedure noted in Section 6.5.8.1 applies to regulated parties that store or bury other waste materials such as ash, tailings or sludge on their own properties. Annual cash payments or annual increases in non-cash forms may be allowed for these facilities so long as the operator complies fully with the Ontario Regulation 232/98 conditions. In any event, the full amount of Financial Assurance must be provided at least one year before the site is closed.

6.5.9 Approvals under section 53, OWRA including private communal sewage systems and sewage works in unorganized or organized areas without a municipal government agency agreement to take over the system (See also A.6 in Appendix A)

6.5.9.1 The amount of Financial Assurance required should be equal to 100% of three years of undiscounted operating costs plus 15% of the capital costs sufficient to provide funds for upgrading or clean-up that may be required after a default and for temporary operation by the Ministry until a municipality or another local organization takes over operations.

6.5.10 Approvals under section 9, EPA (See also A.7 in Appendix A)

6.5.10.1 Financial Assurance should be calculated as follows:

a) For specific abatement actions that contain deadlines, the amount of Financial Assurance would be 100% of the capital and all recurring costs to implement all abatement requirements;

b) For the storage of subject waste materials from air pollution control equipment, the amount of Financial Assurance would be 100% of the estimated cost to remove the subject waste from the site and dispose of it in accordance with Ministry standards;

c) For equipment used in the mobile in-situ chemical oxidation process, the amount of Financial Assurance would be based on the number of sites being operated under the certificate of approval, or some other basis deemed acceptable by the Program Director; and

d) Where the compliance projects are to be completed within four years, the amount of Financial Assurance should be 100% of the estimated one-time (capital) costs of replacing the air pollution control equipment with back-up control equipment that is known to control the emissions in question to an acceptable degree as required by the Program Director.

6.5.10.2 Where the compliance projects are to be completed within four years, the amount of Financial Assurance would be 100% of the estimated one-time equipment, removal and installation costs of replacing the air pollution control equipment with back-up control equipment that is known to control the emissions in question to an acceptable degree as required by the Program Director.

6.5.11 Approvals for operations which discharge into surface waters subject to section 53, OWRA

6.5.11.1 Financial Assurance can be required to ensure that compliance with the terms and conditions of an approval are achieved by a specified date.

6.5.11.2 Cost estimates of the required abatement or preventative systems and activities should be provided by the regulated party. If such estimates are not submitted, the Program Director should issue an order to require that the regulated party provide these estimates. The issuing Program Director should confer with the Economic Analysis Section regarding the kind of cost data and other information that should be specified in the order and obtained from the regulated party.

6.5.11.3 Financial Assurance would normally be equal to 100% of the capital costs of implementing the required abatement or prevention systems. If costs are to be incurred over four or more years, the recommended amount of Financial Assurance is equal to the present value of capital and other one-time costs, plus the total annual recurring costs for the entire period.

6.5.12 Permits to take water under section 34, OWRA (See also A.9 in Appendix A)

6.5.12.1 Financial Assurance may be applied to permits to take water (PTTWs) where there is evidence that a water taking by a permit holder could cause adverse external effects to other water users. In cases where water taking under a PTTW are expected to cause external effects (such as depletion of neighbouring wells or excessive reduced stream flows), the PTTW will normally not be issued until actions or adjustments are made to prevent adverse effects. However, in some circumstances, such as a temporary dewatering project, the Program Director may issue the PTTW with the condition of Financial Assurance.

6.5.12.2 The amount of Financial Assurance required for such cases would be 100% of any one-time or capital costs plus 100% of the recurring costs of an acceptable method of providing alternative water supplies over an agreed-to period of time to all potential parties who would be adversely affected. The time period for these estimates should be a minimum of two years, or for a period deemed appropriate by the Program Director, with reasons.

6.5.12.3 The planning period should be determined with input from the PTTW applicant, other potentially affected water users and Ministry experts.

6.5.13 Orders to undertake industrial abatement programs under section 18, EPA (See also A.10 in Appendix A)

6.5.13.1 Financial Assurance may be required as a condition of an order to ensure that:

a) Sufficient funds for compliance are available, and

b) Compliance is achieved by the agreed-to deadline.

6.5.13.2 Financial Assurance should be equal to 100% of the one-time equipment, engineering, installation costs of implementing the required air or water pollution abatement or preventative systems. The implementation costs are to include contingency costs.

6.5.13.3 Financial Assurance for these types of facilities should be retained until all work required to fulfill the terms and conditions of the order is completed and inspected. However, Financial Assurance funds may be returned or released in stages as work is completed and invoices submitted. Ministry staff must be satisfied that other part of the Financial Assurance returned or released is not required in respect of the works. Ministry staff should review Financial Assurance balances and estimated remaining expenditures every six months to ensure that the Financial Assurance balance is sufficient.

6.5.13.4 For example, an industrial sewage or water pollution abatement compliance project that is mandated by an order will take three years to complete. Financial Assurance required would be equal to 100% of the total capital cost of the compliance activities plus contingency costs. Equipment and installation costs total $15 million. Financial Assurance would thus amount to $15 million plus an additional $1.5 to $2.24 million for contingencies, to arrive at a total Financial Assurance amount of $16.5 to $17.24 million.

6.5.14 Orders to require decommissioning and remediation of contaminated sites (See also A.11 in Appendix A)

6.5.14.1 An order that requires decommissioning and remediation of a contaminated site may also include conditions to require Financial Assurance. Financial Assurance should be required where one or more of the criteria noted in Section 4.4 paragraph a) apply.

It is presumed that such a site will be remediated so that the site may be used for new construction or other purposes.

6.5.14.2 The amount of Financial Assurance should be equal to 100% of the one-time capital costs for decommissioning and remediation to bring the site into compliance with the terms and conditions of the order and local zoning by-laws. Cost estimates should be made under the assumption that the work will be carried out by a third party contractor.

6.5.14.3 The requirement to estimate costs of the above-noted activities and to report them to the Program Director should be specified as conditions in the order.

6.5.15 Orders involving storage of subject wastes under Regulation 347 (See also A.12 in Appendix A)

6.5.15.1 Financial Assurance to be provided for these facilities is equal to the total cost of removing, transporting and disposing of any materials left on site if the owners or operators ceased operations for any reason and could not, or would not, clean up the site. For purposes of Financial Assurance, these types of sites are similar to those noted in Section 6.5.5 above.

6.6 Payment schedules for short-term (less than four years or when there is no known future date for closure, clean-up or remediation expenditures) cases

6.6.1 Payment schedules refer to the total time period over which regulated parties are to provide the Financial Assurance to the Ministry in an appropriate form.

6.6.2 Normally, for all the above-noted types of "short-term" cases or projects, 100% of the total amount of required Financial Assurance should be provided to the Ministry before the commencement of operations or as otherwise directed by the Program Director.

6.6.3 In the case of waste processing and transfer facilities, if the facility begins operating below its approved capacity, the Program Director may allow the regulated party to submit only a portion of the required Financial Assurance that is in proportion to the amount of material that is brought on site during the beginning months of operation. It is recommended that audits of quantities on site and adjustments of Financial Assurance payments/deposits for such establishments be conducted quarterly.

6.6.4 Elements of the payment schedule should be specified as conditions in an order or approval. Reasons for obtaining less than 100% of total Financial Assurance for any case or project should be noted in the order or approval and in a note to file.

6.6.5 If the Program Director chooses to withhold an approval until the Financial Assurance is received:

a) The Program Director may send a copy of the draft approval to the proponent and explain that the approval is ready to be issued when Financial Assurance is provided under the proposed Financial Assurance conditions. If Financial Assurance is not provided, the Program Director can refuse to issue the approval, or

b) A condition of the approval may state that a waste disposal or processing facility cannot start receiving waste until the applicant provides Financial Assurance in accordance with relevant conditions.

6.7 Estimating Financial Assurance when the planning period is four or more years or when there is a known future date for closure, clean-up or remediation expenditures

6.7.1 Where the planning period of an order or approval is four or more years or when there is a known future date for closure, clean-up or remediation, discounting of future costs is permitted. This means that regulated parties can provide an initial amount of Financial Assurance that can grow by means of interest paid on cash deposits or through annual increases in non-cash forms until the balance reaches the amount needed for the specified compliance activities in the future.

6.7.2 For a landfill, the costs of closure and post-closure monitoring and maintenance of a site that will be incurred in future years can be discounted using procedures discussed in this Section. The sum of these future, discounted costs is the present value (PV) and is equal to part of the Financial Assurance that would be required. Financial Assurance is also required for contingency costs. The PV of future closure or post-closure costs and the Financial Assurance for contingency costs are summed to derive the total Financial Assurance amount.

6.7.3 The types of approvals or activities which may involve planning periods of four years or longer or when future costs will be required by a certain date include:

a) Private municipal waste landfilling sites (Section 6.7.7);

b) Incineration facilities including sites burning waste derived fuels (WDF) for which future decommissioning expenses must be incurred (Section 6.7.8);

c) Industrial and milling activities that generate tailings or ash, section 53, OWRA (Section 6.7.9);

d) Sewage works that generate waste materials (sludges) that are stored and remain on the site until and after decommissioning, section 53, OWRA (Section 6.7.10); and

e) Industrial abatement programs, section 18, EPA (Section 6.7.11).

6.7.4 The generic procedure and steps to compute Financial Assurance for these types of orders, approvals and activities are listed below. Further information and explanations about each step are presented in subsequent sections and appendices of this Guideline.

a) Produce documented estimates of all relevant one-time and recurring cost items;

b) Provide a schedule of the entire planning period showing the years when each cost item is to be incurred. Planning periods vary by facility:

   i) For landfills, planning period is equal to the operating period of the facility plus the contaminating life span of the landfill after closure;

   ii) For private incinerators, the planning period includes the construction, operation and ultimate decommissioning of the facility;

   iii) For industrial and milling activities that generate tailings or ash, the planning period is similar to the landfill planning period stated in i) above;

   iv) For sewage treatment facilities that generate waste materials such as sludges that are stored and remain on the site until and after decommissioning, the planning period is similar to the landfill planning period stated in i) above; and

   v) For orders that require water or air pollution abatement programs, the planning period starts with the date that the order is issued and ends with the last completion deadline specified in the order. Completion means that the Program Director has agreed that compliance with the order is satisfactory;

c) Using inflation rates specified below in Sections 6.7.6.2 and 6.7.6.3 to inflate all cost items annually until the cost items are no longer incurred;

d) Discount each cost item back to a pre-specified base year using discount rates indicated below in Sections 6.7.6.4 and 6.7.6.5;

e) The base year for landfills which are subject to Ontario Regulation 232/98 will be the year when the landfill closes. The base years for other types of activities must be defined in the order or approval; and

f) Sum the PVs for closure and post-closure and maintenance costs and the Financial Assurance for contingency costs to derive the total Financial Assurance required.

6.7.5 The estimates and computations described in Section 6.7.4 should be provided to the Ministry in spreadsheet formats so that all relevant formulas are clearly revealed. Microsoft Excel or Corel Quattro Pro platforms are acceptable. Documentation for all estimates of one-time and recurring cost items should also be provided. Appendix H presents an example of such documentation and spreadsheets for a landfill site.

6.7.6 Inflation and discount rates and procedures

6.7.6.1 For landfill sites that began operation after August 1, 1998 and where the total waste disposal volume is over 40,000 cubic metres, the annual inflation rate shall be derived using the base year of 1997 and the most recent available Annual Average Non-Residential Building Construction Price Index for Toronto (NRCPIT) published by Statistics Canada, Catalogue 62-007. This benchmark index is specified by Ontario Regulation 232/98. The NRCPIT can also be obtained from the Statistics Canada website. The procedures are presented in Appendix K. The NRCPIT is used in the procedure for computing annual inflation rates between 1997 and the most recent available index value presented in Section 6.7.6.2.

The Consumer Price Index is not acceptable for Financial Assurance calculations. Average inflation rates over prior years are also not acceptable. (See also Section 6.7.6.7)

6.7.6.2 To compute the annual inflation rate percentage used to inflate cost items for Financial Assurance purposes:

a) Subtract the most recent published annual average Non-Residential Building Construction Price Index for Toronto (NRCPIT) from the 1997 NRCPIT,

b) Divide by the 1997 NRCPIT, and

c) Divide the result by the number of years between most recent year and 1997 plus 1 to obtain the annual average per cent change.

For example,

2003 NRCPIT = 123.8

1997 NRCPIT = 100

inflation rate = [(2003 NRCPIT - 1997 NRCPIT) ÷ 1997 NRCPIT] ÷ (2003 - 1997 + 1)

= [(123.8 - 100) ÷ 100] ÷ (2003 - 1997 + 1)

= [23.8 ÷ 100] ÷ 7

= 0.034 or 3.4% per year

6.7.6.3 Costs are inflated from year to year by means of the following formula applied iteratively:

$F(n+1) = C(n) \times (1+i)^n$

where,

n = year 0, 1, 2, 3, ..., N

year 0 = base year = year when project is initiated

N = final year of planning period

F(n+1) = future capital and operating costs in year n+1

C(n) = annual capital and operating costs expended in year n; initial capital and operating costs expended in year n = 0

i = inflation rate derived from NRCPIT

When inflating, base year is equal to n = year 0 of the planning period but for all other purposes, the base year is equal to n+1 = 0+1 = year 1 of the planning period. If the annual expenditures are expected to be incurred each year through the last year of the planning period (which is equivalent to the last year of the contaminating life span), then the expenditures should be inflated until the last year of the planning period, which is equal to N-1 for inflating purposes, but for all other purposes, the last year is equal to N. N is defined as the final year of the planning which is also the final year of the contaminating life span.

For example, using the inflation rate derived in Section 6.7.6.2 above, and a Cost(n) = $1,000, the inflated cost over three years would amount to:

First year: $F(0+1) = \$1,000 \times (1.034)^0 = \$1,000$ current dollars therefore, no inflation

Second year: $F(1+1) = \$1,000 \times (1.034)^1 = \$1,034$

Third year: $F(2+1) = \$1,000 \times (1.034)^2 = \$1,069$

6.7.6.4 Except where discount rates are specified by regulation, price indices or interest rates used to derive discount rates for the purposes of Financial Assurance calculations must be based on the most recent available published values of the relevant benchmark indices or interest rates. Current (nominal), as opposed to constant (real), discount rates are to be used. Regulated parties should use the most recent available published Government of Canada Benchmark Bond Yields: Long-Term (which may be found in the Bank of Canada website, www.bankofcanada.ca) for Financial Assurance discounting computations. Averages of these interest rates over prior years are not acceptable. Real discount rates or “spreads” between interest and inflation rates are not appropriate for Financial Assurance computations described in this Guideline.

If rates from sources other than those cited in this Guideline are proposed, they should be published and accessible to the proponent and the Ministry.

6.7.6.5 Costs in a given year may be discounted with the following procedure:

PV Cost(n+1) = $\sum$(sum of) [F(n) ÷ $(1+r)^n$]

where,

n = year 0, 1, 2, 3, 4, 5, ..., N

year 0 = base year: in the case of landfills, year of site closure, when discounting

year N = final year of planning period (or of contaminating life span for landfills)

F(n) = future (inflated) capital and operating costs

PV Cost(n+1) = present value of future capital and operating costs in year n+1

r = discount rate

For example, the PV of $1,000 in year 10 at a 5% discount rate:

PV Cost(9+1) = \$1,000 ÷ $(1.05)^9$

= \$1,000 ÷ 1.55133

= \$645

The sum of the PVs is expressed by:

Cost(0+1) ÷ $(1+r)^0$ + Cost (1+1) ÷ $(1+r)^1$ + Cost(1+2) ÷ $(1+r)^2$ + Cost(1+3) ÷ $(1+r)^3$ + ... + Cost(n+1) ÷ $(1+r)^n$

When discounting, year of closure is equal to n = year 0 of the contaminating life span but, for all other purposes, it is equal to year n+1 = 0+1 = year 1 of the contaminating life span. Therefore, the last year of the contaminating life span is equal to N-1 when discounting, but for all other purposes, the last year is equal to N.

N is defined as the final year of the contaminating life span which is also the final year of the planning period.

6.7.6.6 Inflation and discount rates are generally used as constants over the entire planning period for the facility. However, these rates will actually vary over time. Therefore, it is advisable to review and update these rates and recalculate required Financial Assurance every three years.

6.7.6.7 Most recent published inflation and discount rates or indices are recommended for Financial Assurance computations because:

a) They are most readily available to all parties and they are more likely to incorporate recent market expectations than would averages of past rates or indices;

b) Real discount rates or "spreads" are not appropriate for the two-step inflation-discount procedure used for Financial Assurance; and

c) Using the same benchmark inflation and discount rates and indices for all regulated parties provides for a level playing field among regulated parties.

6.7.7 Private municipal waste landfilling sites (See also A.13 in Appendix A)

6.7.7.1 Financial Assurance requirements for private sector landfill sites should follow Ontario Regulation 232/98 - Landfilling Sites when:

a) The site came into existence on or after August 1, 1998 and was intended, at the time it came into existence, to have a total waste disposal volume of more than 40,000 cubic metres and to accept only municipal waste for disposal;

b) The site is being altered, enlarged or extended on or after August 1, 1998 so that, after alteration, the site's total waste disposal volume will exceed 40,000 cubic metres and will accept only municipal waste for disposal; and

c) Where a landfill is subject to Ontario Regulation 232/98, the amount of Financial Assurance to be provided should be equal to the:

i) present value, at the estimated date of closure, of the costs of planned closure for the largest area that will require final cover,

ii) present value of post-closure care for the entire area of the site for the entire duration of the contaminating life span of the facility, and

iii) contingency costs for the entire area of the site. A numerical example is presented in Appendix H.

6.7.7.2 Financial Assurance for a landfill site that has a total waste volume less than 40,000 cubic metres, or has been operating before August 1, 1998 may, at the discretion of the Program Director, be based on technologies and procedures that differ from those specified in Ontario Regulation 232/98. These alternative procedures are noted in Section 6.7.7.9.

6.7.7.3 Subject to Ontario Regulation 232/98, cost items include one-time (capital) and recurring (annual) costs for:

a) Planned closure;

b) Post-closure monitoring, security, care and maintenance; and

c) Contingency costs.

The planning period consists of the:

a) Remaining operating period of the landfill plus;

b) Post-closure contaminating life span of the landfill (25 years minimum).

6.7.7.4 Ontario Regulation 232/98 states that, if a landfill operator covers and landscapes each filled portion of the landfill within five years, it does not have to provide Financial Assurance for planned closure. This privilege should be granted with care until regulated parties actually demonstrate this behaviour.

6.7.7.5 If filled portions of a site are not covered and landscaped properly within five years, Financial Assurance should be required for the planned closure of the largest area that will require final cover at any one time during the entire operation of the site (including the costs of final cover and landscaping).

6.7.7.6 Steps to calculate Financial Assurance amount for a typical landfill according to Ontario Regulation 232/98 include:

(The following steps are illustrated by the example in Appendix H - Spreadsheet Template for Calculating Financial Assurance Amounts for a Typical Landfill Site, According to Ontario Regulation 232/98.)

a) Confirm the first year of the planning period;

b) Determine the remaining number of operating years, total capacity of landfill and annual fill rate;

c) Determine year of closure and post-closure contaminating life span (minimum 25 years);

d) Generate estimates for all one-time (capital) and recurring cost items associated with planned closure and post-closure maintenance and monitoring activities in current dollars. Planned closure cost estimates should be based on the largest area that will require final cover at any one time during the operation of the site, including the costs of final cover and landscaping;

e) Inflate each cost item up to the last year the cost will be incurred. All closure costs will typically be incurred during the year of closure. Post-closure care and maintenance costs will be incurred annually from the year after closure to the last year of the contaminating life span (minimum 25 years);

f) For illustrative purposes, formulae and instructions for inflating and discounting cost items are described in more detail in Appendix H;

g) Add all the costs incurred in the year of closure. In Table H2, Appendix H, year-of-closure cost items are listed in **bold** in the row entitled “Closure Year 2024.” The sum of these values for the year of closure is shown in Column U, “Undiscounted Future Expenditures $’s”;

h) For each year between closure and the final year of the contaminating life span, sum the care and maintenance expenses. In Table H2, Appendix H, these total post-closure care and maintenance costs are shown in Column U;

i) Sum all the costs listed in Column U to arrive at the total undiscounted future expenditures of $7,938,588;

j) Compute the present values (PV) of each annual total cost through to the final year of the contaminating life span. The PVs of total costs for each post-closure year are shown in Column V, “Closure Year 2004 Expenditures $’s” in Table H2 in Appendix H. The present value computational procedures are explained and demonstrated in Appendix H;

k) Sum the PVs of total closure and post-closure costs incurred in each year through to the last year of the contaminating life span. This summation is shown at the bottom of Column V and totals $2,958,525 in the example provided. As noted, the base year for the PV calculations of the total cost of closure and post-closure costs is the year of closure;

l) As per Ontario Regulation 232/98, use the following formula to compute the contingency cost component of Financial Assurance:

$$F = \$0.50 \times W \times (I_2 \div I_1)$$

where,

F = the amount of the Financial Assurance for contingency costs.

W = the number of tonnes of waste that have been deposited in the landfilling site at the time the amount of Financial Assurance is calculated.

I_1 = the 1997 Annual Average Non-Residential Building Construction Price Index for Toronto (NRCPIT), determined with reference to the same base year as is applicable to I_2, as published by Statistics Canada, Catalogue 62-007. The NRCPIT for 1997 is 100 and is the base year.

I_2 = the most recent NRCPIT available at the time the amount of the Financial Assurance is calculated, as published by Statistics Canada, Catalogue 62-007. For example, the most recent NRCPIT is for the year 2003 = 123.8 whereas 1997 = 100.

Therefore, contingency costs are accumulated over the operating period of the facility. Accumulated Financial Assurance for contingency costs is shown in Column AA, "Financial Assurance Accumulated for Contingency Costs" in Table H2 in Appendix H. For example, the total estimated amount of Financial Assurance in Appendix H is shown in Row 26 (2023), Column AA of Table H2 and amounts to $37,140;

m) The Financial Assurance amount to be provided is equal to the sum of the PVs of the total costs of closure, post-closure care costs and Financial Assurance for contingency costs as of the anticipated date of closure, in dollars current at that date. In the example in Table H2, Appendix H, this amount is equal to $2,995,665 as noted in Column AE, "Total Cumulative Financial Assurance Balance"; and

n) In each subsequent year after Financial Assurance has been initially provided, payments must be made to a cash account or the value of non-cash forms such as letters of credit must be increased each year according to the proportion of the total waste that is deposited in the landfill at the end of each year. This process is repeated annually until the site is filled to capacity or closed for other reasons.

6.7.7.7 Where a landfill site is already filled and closed or has only one or two years of capacity left, the Financial Assurance amount is still equal to the sum of the PVs of the total cost of closure, post-closure care and amounts for contingency costs as of the date of closure. However,

a) Little or no Financial Assurance for planned closure is required if the operator has closed and covered the site during its operation. If not, then all relevant closure costs should be obtained as Financial Assurance until the site is closed to the satisfaction of the Program Director;

b) Financial Assurance for post-closure maintenance and monitoring plus contingency costs should be obtained as soon as possible. The amount for post-closure maintenance and monitoring that should be provided is equal to the present value of the total costs over the contaminating life span of the site; and

c) Contingency costs which would be calculated as per Ontario Regulation 232/98 and Section 6.7.7.6, paragraph l), above.

6.7.7.8 As per Ontario Regulation 232/98, Financial Assurance for contingencies may not be required for:

a) Individual landfill sites if Financial Assurance for contingency plans is provided by an approved group Financial Assurance plan acceptable to the Program Director;

b) A landfilling site owned by a municipality or the Crown. However, Financial Assurance is required of a Municipal Corporation as noted in Section 3.10; and

c) Landfill sites owned by a forest products company if the waste to be deposited at the site is predominately solid, non-hazardous process waste, such as wood waste, effluent treatment solids, hog fired boiler ash, recycling process rejects, lime mud, grits or dregs.

6.7.7.9 Ontario Regulation 232/98 is the preferred method of calculating Financial Assurance and is mandatory for sites which have been established on or after August 1, 1998 with a capacity over 40,000 cubic metres, and those sites which are altering, enlarging or extending on or after August 1, 1998 so that after the alteration, enlargement or extension the site will have a capacity of over 40,000 cubic metres. The Program Director has the discretion to require other methods for calculating Financial Assurance as conditions of a certificate of approval. Therefore, for landfill sites that began operation before August 1, 1998 or are under 40,000 cubic metres capacity, the Program Director may direct that Financial Assurance be derived from the costs of emergency and planned closure, post-closure and contingency activities described below.

6.7.7.9.1 Cost items used to calculate Financial Assurance include one-time (capital) and recurring (annual) costs for:

a) Emergency closure;

b) Post-closure monitoring, security, care and maintenance for emergency closure;

c) Contingency costs for emergency closure;

d) Planned closure;

e) Post-closure monitoring, security, care and maintenance for planned closure; and

f) Contingency costs for planned closure.

The planning period consists of the:

a) Remaining operating period of the landfill plus;

b) Post-closure contaminating life span of the landfill (25 years minimum for both emergency and planned closure calculations).

6.7.7.9.2 Emergency Closure

a) Emergency closure means that a site is closed prior to the planned closure date for some reason. For emergency closure estimates, the filled area to be covered and rehabilitated each year is equal to the proportion of the site that is filled each year;

b) The planning period is equivalent to the contaminating life span because it is assumed that emergency closure occurs in the first year of operation for the purposes of Financial Assurance computation. The time period for the contaminating life span is a minimum of 25 years;

c) Generate one-time capital, annual operating and maintenance costs for emergency closure, post-closure and maintenance and contingency costs for the 25-year contaminating life span. The first year of operations becomes the year of closure and is considered the first year of the contaminating life span in order to calculate the Financial Assurance. Emergency closure cost estimates should be based on the filled area to be covered and rehabilitated each year. This is equal to the proportion of the site that is filled each year;

d) Unlike Ontario Regulation 232/98, a formula is not used to calculate contingency costs. These costs consist of the costs for potential leachate and gas collection and treatment facilities, along with other possible costs noted in Appendix A. The amount of Financial Assurance should equal the estimated one-time costs plus at least one year of operating costs;

e) Inflate each cost item from year of closure (year 1) until the end of the contaminating life span using the inflation and discount rates noted in this Guideline;

f) Discount the future costs back to the year of closure (year 1);

g) Follow the same inflation and discount procedures found in Section 6.7.7.6;

h) The Financial Assurance amount to be provided is equal to the sum of the present values for emergency closure, post-closure care and maintenance and contingency costs, as of the year of closure (= year 1), in dollars current at that date;

i) Relevant financial parameters (e.g., inflation and discount rates) and cost items should be updated every three years or as otherwise required by the Program Director; and

j) 100 per cent of the emergency Financial Assurance amount is required before the facility begins operations or as otherwise directed by the Program Director.

6.7.7.9.3 Planned Closure

a) Planned closure generally occurs when the landfill reaches approved capacity. The cost estimates are based on the largest area that will require final cover at the end of the operating period of a landfill site;

b) Planning period is defined as the operating period plus the contaminating life span. This will result in a minimum of 25 years for the contaminating life span plus the number of years during the operating period; and

c) Follow the same procedures noted in Section 6.7.7.9.2 except for the following:

   i) Inflate each cost item up to the last year the cost will be incurred. All closure costs will typically be incurred during the year of closure. Post-closure care and maintenance costs will be incurred annually from the year after closure to the last year of the contaminating life span (minimum 25 years);

   ii) Discount the future costs back to the anticipated year of closure which is equal to the first year of the contaminating life span;

   iii) The Financial Assurance amount to be provided is equal to the sum of the present values for planned closure, post-closure care and maintenance and contingency costs, as of the anticipated year of closure, in dollars current at that date;

   iv) 100 per cent of the Financial Assurance amount is required five years before the anticipated planned year of closure; and

   v) A difference will exist between the Financial Assurance amounts for emergency closure and for planned closure. This difference can be made up by annually increasing the Financial Assurance amount to arrive to the required total Financial Assurance amount for planned closure. This annual increase will be an equal amount which is calculated by taking the difference between the emergency closure and planned closure amounts and dividing this difference by the number of years between the first year and year in which the planned closure amount must be provided (which is 5 years prior to closure).

   For example,

   if: Financial Assurance for emergency closure (in 2005) = $10,000

   Financial Assurance for planned closure (in 2020) = $40,000

   As per this Guideline, Finance Assurance for planned closure must actually be provided by 2015 (5 years prior to closure).

   The number of years between emergency closure and the year in which planned closure must be provided (2015 - 2005 = 10 years).

   Therefore, the annual increase will be $30,000 ÷ 10 years = $3,000 per year.

6.7.8 Incineration facilities (See also A.14 in Appendix A)

6.7.8.1 Financial Assurance for incinerators is for the purpose of funding the decommissioning of the facility. Since decommissioning would take place more than four years after a plant begins operation, Financial Assurance for the facility would equal the present value of all decommissioning costs.

6.7.8.2 The planning period for a private incinerator includes the construction, operation and ultimate decommissioning of the facility. Decommissioning involves installation of security structures and systems, demolition, removal of rubble and other residues, remediation and clean-up of the site and disposal of all residual materials. So long as ash is not buried on site, it is presumed that the site would be remediated sufficiently for future development. Therefore no post-closure care and maintenance costs are likely. Development of cost estimates for these activities should be required by conditions in the facility certificate of approval.

6.7.8.3 Use present value computational procedures noted in Section 6.7.4 or as otherwise directed by the Program Director. These procedures are similar to the procedures used for landfill sites which are subject to Ontario Regulation 232/98. The estimated operating life of the facility should be consistent with industrial experience and the regulated parties and/or their consultants should provide evidence in support of the operating life they propose.

6.7.8.4 Financial Assurance for private incinerators should be equal to the present value of the total future one-time decommissioning costs.

6.7.9 Approvals under section 53, OWRA for industrial and milling activities that generate tailings or ash (See also A.15 in Appendix A)

6.7.9.1 Financial Assurance may be required to finance site closure and rehabilitation of tailings, slag or other waste material storage areas and for long-term care. The amount of Financial Assurance required should include 100% of the present value (at the time of closure) of the total costs of planned closure and rehabilitation activities, plus costs of long-term monitoring, maintenance and contingency plans as required by the Program Director.

6.7.9.2 Present value computational procedures are similar to those for landfills. The time period for present value calculations is the contaminating life span of the disposal facility or a time period that is otherwise acceptable to the Program Director.

6.7.9.3 If the regulated party is a mining company under the authority of the *Mining Act*, it may have provided Financial Assurance to the Ministry of Northern Development and Mines (MNDM) to finance the firm's site closure plan. If a mining operation is issued an order or approval, Ministry of the Environment staff should confer with the "mines group" of MNDM in Sudbury to ensure that sufficient Financial Assurance has been provided to pay for compliance costs of Ministry of the Environment requirements in addition to the provisions of the site closure plan. If Financial Assurance for site closure will not cover the costs of Ministry of the Environment requirements, additional Financial Assurance should be obtained by MNDM.

6.7.9.4 The Ministry of the Environment has a Memorandum of Understanding with MNDM with regard to Part VII of the *Mining Act*.

6.7.9.5 MNDM will require that Financial Assurance be provided for all filed or approved Closure Plans. Ministry of the Environment retains authority to require Financial Assurance, pursuant to Part XII of the *Environmental Protection Act*, to address any environmental measures not covered in the Closure Plan or any mining activity not covered by the *Mining Act*. Where agreement between the ministries of the Environment and Northern Development and Mines is put in place, this Financial Assurance may also be included in the amount held by MNDM.

6.7.9.6 For ash and tailings disposal by non-mining industrial facilities, present value computational procedures are similar to those for landfill sites subject to Ontario Regulation 232/98.

6.7.9.7 The Financial Assurance amount to be provided is equal to the sum of the present values of the total one-time (capital) and recurring costs for:

a) Closure;

b) Long-term post-closure care; and

c) The Financial Assurance amount for contingency costs as of the anticipated date of closure, as required by the Program Director, in dollars current at that date.

6.7.9.8 The time period for present value calculations should be the contaminating life span of the tailings or ash deposits of the disposal facility or a time period that is acceptable to the Program Director.

6.7.9.9 As with landfills, the amount of Financial Assurance on deposit each year should be increased so that the amount of money accumulated by the time the disposal facility is closed will be sufficient to pay for post-closure care. The quantity and/or area of waste materials that are generated each year should be monitored so that sufficient funds will be available to cover long-term care from the time that the facility closes to the end of the contaminating life span or the time period agreed to by the Program Director.

6.7.10 Approvals under section 53, OWRA for sewage works that generate waste materials (sludges) that are stored and remain on the site until and after decommissioning (See also A.16 in Appendix A)

6.7.10.1 Assuming the Financial Assurance is for the costs of the long-term storage and maintenance of sludges and other waste materials on site, follow procedures for a landfill site subject to Ontario Regulation 232/98.

6.7.10.2 If the waste materials are to be removed from the site upon decommissioning, the amount of Financial Assurance should be based on the costs of loading, hauling and disposing of the waste solids, similar to the costs associated with a transfer or waste processing facility. All relevant clean-up requirements that are to be included should be noted in the certificate of approval.

6.7.10.3 Sections 6.7.9.6 through 6.7.9.9 noted above may also apply to sewage works that generate waste materials such as sludge, at the discretion of the Program Director.

6.7.11 Orders to undertake industrial abatement programs under section 18, EPA that will last four or more years or have a specified date for closure, clean-up or remediation (See also A.10 in Appendix A)

6.7.11.1 Financial Assurance may be required as a condition of an order to ensure that:

a) Sufficient funds for compliance are available, and

b) Compliance is achieved by the agreed-to deadline.

6.7.11.2 The order should include a condition to direct the regulated party to provide a work program with completion dates of each phase or stage or major component of the project.

6.7.11.3 Capital and other one-time costs of each stage of the project and any future contingencies must be estimated.

6.7.11.4 Cost to be incurred each year greater than year 3 are to be discounted. Costs incurred in year 1 through 3 should not be discounted.

6.7.11.5 Financial Assurance to be provided is the sum of the undiscounted costs to be incurred in years 1 to 3 plus the sum of the discounted costs to be incurred in all years beyond three.

6.7.11.6 Financial Assurance for these types of facilities should be retained until all work required to fulfill the terms and conditions of the order is completed and inspected. However, Financial Assurance funds may be returned or released in stages as work is completed and invoices submitted. Ministry staff must be satisfied that other part of the Financial Assurance returned or released is not required in respect of the works. Ministry staff should review Financial Assurance balances and estimated remaining expenditures every six months to ensure that remaining Financial Assurance is sufficient.

6.8 Payment schedules for facilities and operations when the planning period is four or more years or when there is a known future date for closure, clean-up or remediation expenditures

6.8.1 Unless otherwise specified by regulation, all required Financial Assurance for a site, facility, or activity should be obtained in satisfactory form before a facility begins operation or as otherwise directed by the Program Director.

6.8.2 Ontario Regulation 232/98 allows private landfill owners of new or expanded sites, after August 1, 1998, to provide Financial Assurance annually in proportion to the degree to which the landfill capacity is filled. For example, at the end of year 5, if 25% of the permitted capacity is used, at least 25% of the total Financial Assurance required should be provided. These requirements should be specified as conditions in an order or approval.

6.8.3 Where a regulated party is allowed to provide Financial Assurance in installments, appropriate cash payments must be deposited each year or the value of a non-cash form must be increased each year according to a schedule that was submitted as part of the initial Financial Assurance proposal and should be incorporated as a condition in the order or approval.

6.8.4 The total Financial Assurance amount must be provided in full at least one year prior to the expected closure year or decommissioning of a particular facility. Financial Assurance payment schedules should be included as conditions of orders or approvals.

6.8.5 The Financial Assurance account balance should be reviewed annually to ensure that it has been increased from year to year. The Financial parameters and cost items that are used to calculate Financial Assurance should be reviewed at least every three years or as specified by the Program Director in order to ensure that the Financial Assurance is sufficient to cover the estimated costs.

6.9 Use of Financial Assurance by owners and operators

6.9.1 If the owner or operator of a facility or site wants to use any of its Financial Assurance for any compliance-related purpose before the facility is closed, the owner or operator of a site must

a) Obtain approval from the Program Director;

b) For landfill sites, ensure that any amount of Financial Assurance utilized is replaced within six months, unless the Program Director directs otherwise; and

c) For all other facilities, ensure that any amount of Financial Assurance utilized is replaced within three months, unless the Program Directors directs otherwise.

6.10 Reductions in the amount of Financial Assurance required

6.10.1 Regulated parties sometimes ask to have Financial Assurance obligations reduced because of financial hardship. Some regulated parties may ask to provide only a fraction of the total Financial Assurance required at the outset of their operation until they “build up their business” or “can better afford the Financial Assurance.” Parties who ask for such considerations should be reviewed carefully before an approval is issued. They could be vulnerable to failure if economic conditions deteriorate and could constitute a risk of leaving a site remediation problem with little or no Financial Assurance. Financial Assurance is a necessary cost of doing business and is needed to internalize the environmental risks that would otherwise be borne by the public. Businesses should not be subsidized and should provide their fair share of Financial Assurance.

6.10.2 Operators of waste processing or recycling facilities may also ask to deduct the estimated market values of saleable materials that are on their site from required Financial Assurance. The Program Director may, as a condition in an order or approval, deduct the estimated volume or weight of secondary materials that may be sold or otherwise removed free of charge from the removal cost calculations noted in Section 6.5.5.3. Values of saleable materials may not be used because market values for secondary materials can fluctuate rapidly and widely. Also prices and values of materials are difficult to verify and buyers of saleable materials often reject loads altogether if they contain contaminating materials. Documentation should be provided in the form of letters, contracts or written commitments from receivers or other legitimate firms that they will take the materials off-site free of charge.

6.10.3 The Program Director may reduce Financial Assurance for waste management systems (haulers), if the regulated party can document the following:

a) The hazard or risk level of material being hauled is low;

b) The accident frequency is below average for all permitted waste management systems; and

c) The applicant has no record of environmental infractions or convictions.

7. Issuing Orders and Approvals with Financial Assurance Requirements and Accepting, Obtaining and Handling Financial Assurances

7.1 Section 7.2 defines responsibilities for estimating and providing the information and cost estimates needed to determine the amount of Financial Assurance required, as described in Section 6. Section 7.3 presents procedures involved in accepting, receiving and handling all forms of Financial Assurance. Section 7.4 lists the procedures for specific forms of Financial Assurance. Also note,

a) If satisfactory Financial Assurance is not received according to the terms and conditions of the order or approval, the Program Director should take immediate actions such as issuing orders, or even revoking the approval in accordance with Ministry guidelines, procedures and policies and in consultation with Legal Services Branch. Normally, an approval should <u>not</u> be revoked if waste is already on the site. Revoking the approval will remove an important legal authority that the Ministry has to require compliance with other (non-Financial Assurance) conditions in the approval. If waste is on the site, staff should amend the approval to stop operations or to prohibit waste being brought to the site. Such an amendment should not affect any other conditions in the approval.

b) If the person to whom the order is directed or the approval is issued is different from the person or firm posting the Financial Assurance, the Program Director should verify the Financial Assurance amount and the conditions in the order or approval for which the Financial Assurance was issued and ensure that this arrangement is appropriate.

A flow chart presented in Appendix F demonstrates the main steps for the proper administration of obtaining and handling Financial Assurance.

7.2 Responsibilities for estimating relevant costs for Financial Assurance requirements

7.2.1 Regulated parties are responsible for providing cost estimates for the relevant compliance activities required to fulfill the terms and conditions in the order or approval. If cost estimates are not submitted, the approval proposal and application may be returned to the regulated party.

7.2.2 Ministry of the Environment officials will then review and verify, to the extent possible, estimates submitted by regulated parties. Verification may be accomplished by site visits, calling vendors, reviewing other approval files for landfills and by reviewing the literature in trade magazines.

7.2.3 Appropriate Ministry guidelines, procedures or policies, such as *Guideline F-2, Compliance Guideline*, should be invoked to aid in resolving any disagreement between the Ministry and the regulated party on Financial Assurance amounts and any other Financial Assurance matter.

7.2.4 If the regulated party claims that provision of the Financial Assurance may cause unemployment or undue financial hardship, an economic or financial analysis should be carried out to verify these claims. This analysis should be completed in accordance with appropriate Ministry guidelines, procedures or policies, such as *Guideline F-14, Economic Analyses of Control Documents on Private Sector Enterprises and Municipal Projects*.

7.2.5 If cost estimates cannot be agreed to between the regulated party and the Ministry, the Ministry will have final determination of the value of the costs and Financial Assurance amount.

7.3 Acceptance, receipt and handling of all forms of Financial Assurance

7.3.1 The Financial Assurance proposal and Financial Assurance amount should be submitted initially to the Program Director.

7.3.2 For orders that have Financial Assurance requirements, copies of all documentation should be sent to the Environmental Assessment and Approvals Branch. For approvals, copies of all documentation should be sent to the relevant Regional and District Offices. In addition, the Program Director should, at the very least, ensure that a copy of the following be sent to the Business and Fiscal Planning Branch for review, retention and record keeping:

a) The front page of the order or approval;

b) The signature page or pages of the order or approval;

c) The pages containing any Financial Assurance conditions and requirements; and

d) Any relevant cover letters, communications or information.

7.3.3 The Program Director should ensure that cash and signed originals of Financial Assurance forms and original supporting documents are delivered to the Business and Fiscal Planning Branch for safekeeping.

7.3.4 The Program Director, the Business and Fiscal Planning Branch and the Environmental Assessment and Approvals Branch should review the original Financial Assurance amount and documents once they have been obtained from the regulated party to ensure, at a minimum, correct spelling of regulated party’s name and address, consistency of data and estimates and receipt of all required information.

7.3.5 Standard or non-standard, non-cash forms of Financial Assurance such as letters of credit or surety bonds should only be accepted from financial or other institutions empowered to issue such forms and with business offices or branches located in Ontario. A list of such institutions can be obtained from the Business and Fiscal Planning Branch or from the Ministry of Finance.

7.3.6 In order for the Ministry to accept Financial Assurance from companies which reside outside of Canada, the issuing foreign-owned bank, surety or insurance company should have offices in Ontario; an affiliated bank or company which is domiciled in Ontario or the foreign-owned bank should issue paper that would be acceptable to a bank in Ontario. The Ontario institution must provide written acceptance of the obligation to be bound by the form of Financial Assurance issued outside of Ontario.

7.3.7 The regulated party is responsible for all fees and charges imposed by the issuing financial institution.

7.4 Acceptance, receipt and handling of specific forms of Financial Assurance

7.4.1 Standard, non-standard and unacceptable forms of Financial Assurance are described in Section 5.

7.4.2 Any new, non-standard forms of Financial Assurance (including insurance policies and trusts) should be reviewed by staff in the Legal Services Branch, the Economic Analysis Section and any other staff as requested by the Program Director to determine whether the form is acceptable. During the review and finalization of the wording of a new form of Financial Assurance, the regulated party is required to provide Financial Assurance in one of the standard forms listed in Section 5.4.1.

7.4.3 Procedures for accepting, obtaining and handling the following forms of Financial Assurance are presented in the subsequent sections:

a) Cash (Section 7.4.4);

b) Irrevocable letters of credit (Section 7.4.5);

c) Surety bonds (Section 7.4.6);

d) Negotiable securities issued by provincial and federal governments (Section 7.4.7);

e) Agreements, contracts, or other non-standard forms of Financial Assurance with conditions specified in the order or approval (Section 7.4.8);

f) Insurance policies (Section 7.4.9);

g) Marketable securities: stocks and shares (Section 7.4.10);

h) Any security or collateral accepted by the Program Director (Section 7.4.11); and

i) Qualified Environmental Trust accompanied by letter of credit (same procedures as irrevocable letters of credit, Section 7.4.5).

7.4.4 Procedures to handle cash

7.4.4.1 Cash refers to cheques and other similar cash equivalents, such as money orders. All cheques should be certified.

7.4.4.2 Cash in the form of currency (dollars) should not be accepted as Financial Assurance. However, if use of cash is unavoidable, staff should give a receipt to the regulated party and keep a copy of the receipt. Staff should then place the cash in a safety deposit box at a convenient bank branch and call Business and Fiscal Planning Branch for instructions. In no circumstances should currency be accepted in amounts greater than $10,000. If funds are to be received from outside of Canada through an electronic transfer and the value of the transfer is $10,000 or more staff should contact Legal Services Branch to determine whether provisions of the *Proceeds of Crime (Money Laundering) and Terrorist Financing Act* are applicable to the transaction.

7.4.4.3 Periodic contributions may be made by the regulated party in order to accumulate a fund for long-term care and maintenance of a landfill or a contaminated site. A cash account is readily accessible to the Ministry, does not require interaction with other institutions to retrieve the funds and does not require monitoring of the value or renewal of a time-limited agreement for the Financial Assurance amount. Non-cash forms of Financial Assurance (such as letters of credit, surety bonds and negotiable securities guaranteed by government) will normally have to be monitored and increased annually in accordance with a schedule specified in the order or approval.

7.4.4.4 An order or approval should always state that, if an uncertified cheque is provided, the Financial Assurance is not considered to be accepted by the Ministry until the cheque has cleared the bank.

7.4.4.5 Cheques, money orders and other cash equivalents should be made out to the Ontario Minister of Finance.

7.4.4.6 Cash will be deposited into an interest-bearing account within the Consolidated Revenue Fund (CRF) and administered by the Business and Fiscal Planning Branch in accordance with appropriate financial policies of the Ministry of the Environment and the Government of Ontario guidelines.

7.4.4.7 Cash should <u>not</u> be deposited in the CRF by the Program Director or by Ministry staff from Environmental Assessment and Approvals Branch or Regional Offices. Cash should be deposited only by Business and Fiscal Planning Branch staff. However, if staff (other than Business and Fiscal Planning Branch) receive cash or cheques, staff are to follow the procedure in Section 7.4.4.2 above.

7.4.4.8 The interest credited to the CRF account shall be at the rate determined in accordance with the Ontario Financing Authority's Tiered Rate and as specified by relevant Orders in Council.

7.4.5 Irrevocable letters of credit

7.4.5.1 An irrevocable letter of credit is a document issued by a bank on behalf of a customer which guarantees payment by the bank from the account of the customer to representatives of the Ministry.

7.4.5.2 An order or approval which requires Financial Assurance must include a condition which requires that an automatic renewable clause be included in the letter of credit. The condition should state that the letter of credit will be renewed automatically (with no further documentation) on its expiry date with the same terms and conditions including the condition for renewal. The order or approval must state that, if the letter of credit will not be automatically renewed, the issuing bank must give notice to the Program Director at least 60 days before the expiry date of the letter of credit indicating that the letter of credit will not be renewed.

7.4.5.3 For existing letters of credit which do not have automatic renewal clauses, Ministry staff should monitor the letters of credit to determine the status of the form and ensure that work, for which Financial Assurance is provided, is completed before the expiry date.

7.4.5.4 If a notice not to renew a letter of credit is given by the issuing bank, an alternative form of Financial Assurance satisfactory to the Program Director and the Business and Fiscal Planning Branch must be provided to the Program Director at least 30 days before the expiry date of the letter of credit.

7.4.5.5 Letters of credit should be monitored by Ministry staff to ensure that the documents have not expired.

7.4.5.6 If the regulatory instrument is an approval, the identification number and site location should be clearly indicated on the letter of credit. If the regulatory instrument is an order or the facility is not a specific site, then some other clear, unambiguous description or identification should be indicated on a letter of credit, such as the date of the order.

7.4.5.7 Original letter of credit documents are held by the Business and Fiscal Planning Branch.

7.4.5.8 Appendix E provides an example of an irrevocable letter of credit with wording that is acceptable to the Ministry.

7.4.6 Surety bonds

7.4.6.1 Surety bonds consist of agreements or contracts among the guarantor (a surety or bonding firm), the regulated party, and the Crown. The bonds are held in a secure location in the Business and Fiscal Planning Branch.

7.4.6.2 Surety bonds are to be negotiated by the Program Director with the assistance of the Business and Fiscal Planning Branch, the Legal Services Branch and the Economic Analysis Section.

7.4.6.3 For existing surety bonds which do not have automatic renewal clauses, Ministry staff should monitor these bonds to determine the status of the form and ensure that work, for which Financial Assurance is provided, is completed before the expiry date.

7.4.6.4 Where a surety bond specifies an expiry date, the Program Director should ensure that the surety bond does not expire until after the end of the planning period so that all requirements of the order or approval can be completed. The surety bond must include the provision that the guarantor give notice to the Program Director at least 60 days before the expiry date of the bond indicating that the bond will not be renewed.

7.4.6.5 If a notice not to renew a bond is given by the guarantor, another form of Financial Assurance satisfactory to the Program Director and the Business and Fiscal Planning Branch must be provided to the Program Director at least 30 days before the expiry date of the surety bond.

7.4.6.6 Surety bonds should be monitored by Ministry staff to ensure they have not expired.

7.4.6.7 Surety bonds are held in a secure location in the Business and Fiscal Planning Branch.

7.4.6.8 Appendix E provides an example of a surety bond with wording acceptable to the Ministry.

7.4.7 Negotiable securities issued by provincial and federal governments

7.4.7.1 Government bonds are issued or guaranteed by the Government of Canada or a provincial government.

7.4.7.2 Government bonds used as Financial Assurance should have a maturity date of not more than three years from the date on which they are deposited.

The use of government bonds as assurance for a period longer than three years is not encouraged because the value of these bonds could fluctuate according to market conditions. If bonds are used, it will be necessary to monitor their value and to compare current values against the expected amount of money that will be required for decommissioning or clean-up and to require the deposit of additional Financial Assurance as necessary.

7.4.7.3 Government bonds should not be accepted without review by the Legal Services Branch, the Business and Fiscal Planning Branch and/or the Economic Analysis Section.

7.4.7.4 The Business and Fiscal Planning Branch holds all original Financial Assurance bonds as well as supporting documents for safekeeping. Bonds must be in bearer form or they must be issued to the Ontario Minister of Finance.

7.4.8 Agreements, contracts or other non-standard forms of Financial Assurance with conditions specified in the order or approval

7.4.8.1 Agreements, contracts and other non-standard forms of Financial Assurance may be considered. However, the Program Director should seek the advice of the Legal Services Branch, Economic Analysis Section and Business and Fiscal Planning Branch before accepting these forms of Financial Assurance.

7.4.8.2 Once the principles and wording in the agreements or contracts are agreed to, the elements should be specified as conditions in the order or approval.

7.4.8.3 Agreements that involve holding of securities by a third party, or bank accounts individually or jointly held by the regulated party, should not be accepted by the Ministry.

7.4.8.4 Guaranteed Investment Certificates (GICs), which are not transferable, should not be accepted as Financial Assurance unless they are reissued payable to the Ontario Minister of Finance.

7.4.8.5 Regulated party or guarantor should have offices, facilities and assets in Ontario.

7.4.9 Insurance policies

7.4.9.1 Insurance may be considered as Financial Assurance on a case-by-case basis.

7.4.9.2 An insurance policy is not appropriate for facilities which require long-term care and maintenance such as landfill sites where a fund must be increased over time to pay for future closure, clean-up and long-term care and contingency costs.

7.4.9.3 Insurance policies should only be considered as Financial Assurance for facilities and activities with planning horizons of less than four years or where the need to incur costs in the future is uncertain. Insurance is not an appropriate form of Financial Assurance for landfills and long-term disposal facilities where it is certain that costs will be incurred in the future. Insurance may be appropriate for facilities such as waste processing and recycling facilities, transfer stations and sewage treatment plants that will eventually be transferred to a municipality. Insurance policies may also be considered for certain types of orders. Insurance policies offered as Financial Assurance are subject to the following conditions:

a) Wording of the policy must be reviewed by the Legal Services Branch;

b) A policy issued by an insurance company must use the same wording in all subsequent renewals issued;

c) A policy should be clear and concise with all relevant provisions and commitments included in the policy. Where possible, “side agreements” should be avoided;

d) Financial Assurance should be provided in an acceptable standard form (for example, cash, letter of credit, surety bond, etc.) until the insurance policy is drafted, approved and issued;

e) Any deductible must be provided by the regulated party as extra Financial Assurance in an acceptable standard form (for example, cash, letter of credit, surety bond, etc.);

f) Non-payment of the insurance premium by the regulated party will require replacement of the insurance policy with some other acceptable standard form of Financial Assurance;

g) Issuer must give Ministry at least 30 days notice of termination of policy; and

h) Insurance policies should not be accepted without the review and approval of the Legal Services Branch, the Business and Fiscal Planning Branch and/or the Economic Analysis Section.

7.4.10 Marketable securities: stocks and shares

7.4.10.1 Where marketable securities or other negotiable securities are accepted as Financial Assurance, the market value of these securities should be at least 20 per cent in excess of the agreed to amount of Financial Assurance in order to allow for fluctuations in the market prices of these securities. The Business and Fiscal Planning Branch holds all original Financial Assurance marketable securities as well as supporting documents for safekeeping.

7.4.11 Security or collateral

7.4.11.1 Security or collateral submitted as Financial Assurance may be considered. However, the Program Director should seek the advice of the Legal Services Branch, Economic Analysis Section and Business and Fiscal Planning Branch before accepting these forms of Financial Assurance.

7.4.11.2 Holding of securities by a third party, or bank accounts individually or jointly held by the regulated party should not be accepted by the Ministry.

7.4.11.3 Ensure that a procedure is in place so that security or collateral can be realized/obtained from the regulated party.

8. Conversion of Non-Cash Forms to Cash and the Use and/or Return of Financial Assurance

Criteria and procedures for converting non-cash forms of Financial Assurance to cash and for using Financial Assurance to carry out compliance activities and for returning Financial Assurance when it is no longer required.

Criteria used to determine whether Financial Assurance is "impaired" are presented in Section 8.2. Section 8.3 contains procedures used to convert non-cash Financial Assurance form to cash. Section 8.4 describes how Financial Assurance funds may be utilized to undertake clean-up, remediation or other environmental compliance measures. Section 8.5 presents criteria that indicate when to terminate and return Financial Assurance to regulated parties. Two flow charts presented in Appendix F demonstrate the main steps for the proper administration of:

a) Returning Financial Assurance; and

b) Converting non-cash Financial Assurance forms to cash and using the Financial Assurance to implement compliance activities specified in orders and approvals.

Financial Assurance is not a penalty. Financial Assurance should be retained as long as there is a potential need for its use in the future. Financial Assurance should be terminated and returned when it is no longer needed or when the funds have been used to pay for activities that were required in an order or approval.

8.1 When Demand Likely to be Made Against Financial Assurance

8.1.1 Without limiting the scope of sections 135 and 136 of the *Environmental Protection Act*, but as a guide to any issuer of, or person providing, Financial Assurance documentary form, including a bond or a letter of credit, absent special circumstances, it is likely that the bond or letter of credit will be converted to cash under subsection 136 (2) in any one or more of the following circumstances:

a) Where the person to whom the approval is issued or the order is directed and whose due performance of the terms and conditions of the approval or order, or any of them, is secured by the Financial Assurance (the "Principal") defaults in the performance of those terms and conditions, and fails to correct that default within 15 days after the Director demands such correction;

b) Where any formal or informal proceeding for the dissolution of, liquidation of, or winding up of, the affairs of the Principal is instituted by or against the Principal, or where a resolution is passed or any other act undertaken for the winding up of the Principal;

c) Where a receiver or receiver manager is appointed over the general assets and undertaking of the Principal, or the assets in relation to the Financial Assurance is provided, whether by any court or under an agreement, or where proceedings are otherwise taken to enforce an encumbrance against the general assets and undertaking of the Principal or the assets in relation to the Financial Assurance is provided;

d) Where the Principal abandons the assets to which the approval or order relates, or ceases or threatens to cease to carry on its business, or where the Principal makes or agrees to make a bulk sale of its property;

e) Where on reasonable grounds the Director believes that any of the property of the Principal necessary to the performance of the terms of the approval or order has been damaged or destroyed or is in danger of being damaged or destroyed, sold or removed or that any of the acts or events described in this section is about to occur or is likely to occur;

f) Where the Principal defaults in payment of any indebtedness or liability to a bank or other lending institution, whether secured or not;

g) Where the Principal is adjudged bankrupt or becomes insolvent, or a petition in bankruptcy is filed against the Principal, or where the Principal makes an assignment for the general benefit of its creditors, or applies for relief under the *Companies Creditors Arrangement Act*, or Chapter 11 of the United States Bankruptcy Code, or makes a proposal under the *Bankruptcy and Insolvency Act*, or where any other proceeding of any type is instituted in any jurisdiction in respect of the alleged insolvency or bankruptcy of the Principal.

8.1.2 In the event of a change in circumstances, including an event described in paragraph g) above, that may trigger a demand on documentary Financial Assurance, it may be necessary to re-evaluate the nature of the work based on which the amount of the Financial Assurance has been calculated.

8.2 Situations contributing to the impairment of Financial Assurance

8.2.1 The Program Director should convert non-cash Financial Assurance to cash as soon as possible whenever Financial Assurance becomes “impaired.” Impaired Financial Assurance means that the sufficiency or the accessibility of the Financial Assurance provided by a regulated party is uncertain in some way.

8.2.2 Financial Assurance becomes impaired when one or more of the following conditions or situations apply:

a) Notice is received, or it otherwise becomes known, that the regulated party, the issuing bank or the guarantor is or is becoming insolvent (for example, a regulated party or its corporate parent party files for credit protection or lays off employees to an unprecedented extent);

b) Notice is received, or it otherwise becomes known, of a proposed cancellation or non-renewal of a non-cash form of Financial Assurance and a satisfactory alternative form of Financial Assurance has not been arranged (sufficiently) prior to the cancellation or expiry of the existing Financial Assurance. Non-renewal means the non-cash form has not been renewed by at least 60 days prior to the expiry date;

c) A site is abandoned and work remains to be done;

d) Notice is received, or it otherwise becomes known, that the enterprise, firm or individual to whom an order or approval is issued ceases to operate or to perform its business activities. Further, there is no new owner or operator of the business who has provided satisfactory Financial Assurance and will continue the operation or activities of the original owner or operator and to whom the original order or approval should be reissued;

e) Inspections or other evidence reveals that a landfill, a waste transfer station or a waste processing facility has accepted, disposed of or stored more material than allowed by the approval; and

f) If there is non-compliance other than that noted in e) above, the significance of the non-compliance, particularly in terms of human health or environmental effects, and the particular circumstances contributing to the non-compliance shall be considered prior to converting the non-cash form to cash or otherwise drawing upon the Financial Assurance.

8.3 Procedures for converting non-cash forms of Financial Assurance to cash

8.3.1 Conversions of non-cash Financial Assurance to cash are to be authorized by the Program Director and undertaken with assistance from the Business and Fiscal Planning Branch. Ministry correspondence to the financial institution and proponent shall reflect the language of the EPA to state that the Financial Assurance will be converted to cash unless the non-cash Financial Assurance is renewed or replaced to the satisfaction of the Program Director.

Correspondence between the Program Director and the Business and Fiscal Planning Branch requesting that non-cash Financial Assurance funds be converted to cash should be accompanied by supporting documentation including, but not restricted to, any relevant order or other documentation.

8.3.2 Cash from converting a non-cash form of Financial Assurance will be deposited to an account in the Consolidated Revenue Fund. Any interest earned on the cash accounts will accrue to the balance of the account and, if necessary, can be used to pay for required activities or projects related to the order or approval under which the Financial Assurance was obtained.

8.3.3 If an operator or a proponent fails to renew a non-cash form of Financial Assurance (i.e., Financial Assurance is not renewed by at least 60 days before it would otherwise expire) or does not provide a new form of Financial Assurance, the Program Director should amend the approval to stop the operations and/or otherwise enforce the order. Also, the Program Director should, at least 30 days before the expiry date, instruct the Business and Fiscal Planning Branch to demand payment in cash from the financial institution if the Financial Assurance is not renewed.

8.3.4 After the Financial Assurance has been converted to cash, the Program Director should claim as much of the available Financial Assurance as is necessary to pay for all work done by the Ministry to complete the terms and conditions of the order or approval. The Program Director should coordinate the access to and use of Financial Assurance with the Business and Fiscal Planning Branch.

8.3.5 Conversion to cash is not necessary if the Program Director has provided written consent that the Financial Assurance is no longer required or if the Program Director has received other Financial Assurance in a form and amount that is sufficient and acceptable.

8.3.6 Flow chart F3 in Appendix F outlines the necessary procedures to convert non-cash to cash.

8.4 Use of Financial Assurance to implement compliance activities

8.4.1 Use of Financial Assurance to initiate, undertake, implement or complete an action, clean-up or environmental measure as specified in the order or approval is to be authorized by the Program Director in a separate order under section 136 of the EPA. The Program Director should give affected parties notice of the proposed order and post the proposed order on the Environmental Registry as required. The order must be directed to:

a) The person to whom the approval or order was issued or any other person who is bound by the approval or order; and

b) Any person that to the knowledge of the Program Director has provided the Financial Assurance for or on behalf of a person referred to in paragraph a), or any successor or assignee of a person that to the knowledge of the Program Director has provided the Financial Assurance for or on behalf of a person referred to in paragraph a).

8.4.2 Where possible, Ministry staff should give regulated parties sufficient notice, usually at least 30 days, of any action to use the Financial Assurance. However Financial Assurance should be converted to cash (prior to using the Financial Assurance) as expeditiously as possible given the situations noted in Section 8.2.

8.4.3 A section 136 Order:

a) Must state that the Ministry may use the Financial Assurance provided for environmental work and that the Ministry may carry out this work;

b) Must specify why the Financial Assurance was originally obtained and how the conditions are not being carried out in accordance with all the requirements of the approval or order;

c) Is a prescribed instrument under the *Environmental Bill of Rights* (EBR), and must be posted on the Environmental Registry for a 30-day public comment period;

d) Is prepared with assistance from Regional solicitors;

e) Is initiated by Program Director; and

f) Is accompanied by the Financial Assurance Refund/Disbursement Form (refer to Appendix I) approved by the Regional Director.

8.4.4 Business and Fiscal Planning Branch should be notified of the intent to access the Financial Assurance and to verify that the Financial Assurance is valid and accessible before the section 136 Order or Notice is issued.

8.4.5 Program Director's correspondence to Business and Fiscal Planning Branch requesting the use of the Financial Assurance funds should be accompanied by supporting documentation such as: Financial Assurance Refund/Disbursement Form signed by the Regional Director, section 136 Order and supporting information such as contractor estimates or invoices.

8.4.6 Sometimes work has to be completed immediately to prevent or mitigate environmental or public health risk and therefore the Ministry cannot wait for the EBR posting to release the Financial Assurance funds. In that case, the order will be posted as an emergency exception.

8.4.7 In these cases, the Ministry shall give notice under subsection 147 (1) of the EPA if the person ordered to do the work is unlikely to do the work promptly or competently; has refused to comply with the order; or, requires assistance with the order. Subsection 147 (1) of the EPA allows the Ministry to hire a different contractor than the one in use by the provider of the Financial Assurance to carry out the activities according to the terms and conditions of the order or approval or to complete the required works. The Program Director shall provide notice under subsection 147 (2) of the EPA to each person required by an order or decision made under the EPA to do the thing, and, if a receiver or trustee in bankruptcy is not required to.

8.4.8 The Ministry or its agent will pay for the costs to complete the work and will be reimbursed from the Financial Assurance account after the EBR posting and appeal period is finished for the section 136 Order. If an agent completes the work, the Ministry must be satisfied with the completion of the work prior to the release of funds.

8.4.9 Where facilities or sites are abandoned, Financial Assurance will be expended on required decommissioning, clean-up and other necessary activities.

8.4.10 Where it is not feasible to utilize outside contractors to complete required environmental works or measures as required by the order or approval (for example, where access cannot be gained to an abatement facility or where compliance requires a process change within a manufacturing plant), and it becomes necessary for the Ministry to convert non-cash Financial Assurance to cash, the Ministry will hold any funds in the Consolidated Revenue Fund until compliance is achieved and compliance requirements are complied with the satisfaction of the Program Director. In such cases, staff in Legal Services Branch should be consulted.

8.4.11 The Program Director should document the steps leading to the conversion of the Financial Assurance to cash and the steps taken to obtain and utilize the Financial Assurance. Where necessary, assistance should be obtained from staff in the Legal

Services Branch and the Economic Analysis Section. Copies of all relevant documentation regarding an order or approval are to be sent to the Business and Fiscal Planning Branch and the Assistant Deputy Minister for the Operations Division of the Ministry.

8.4.12 Flow chart F3 in Appendix F outlines the necessary procedures to use Financial Assurance.

8.5 Return of Financial Assurance

8.5.1 Financial Assurance can be returned to the regulated party under the following conditions:

a) Approval is revoked and the Financial Assurance is no longer needed. If the facility or site is not closed, it is not recommended that an approval be revoked until Legal Services Branch is consulted on the appropriateness of a complete revocation;

b) Work required by the order is completed and the Program Director has verified that the work has been completed satisfactorily;

c) Current holder of the order or approval is replaced by a new holder of the order or approval and the new holder of the order or approval has provided Financial Assurance to the satisfaction of the Program Director. In this case, existing Financial Assurance should be retained until the new Financial Assurance is provided;

d) A change in the issuer of the Financial Assurance which is requested by the current holder of an order or approval. The holder of the order or approval must ensure that the Financial Assurance is replaced. The Program Director should ensure that existing Financial Assurance remains active and in place until the new Financial Assurance is received; and

e) Approval stipulates the return of the Financial Assurance.

8.5.2 Financial Assurance for contingencies can be returned to the regulated party after site closure, if the owner/operator of the landfill site can demonstrate to the Program Director's satisfaction that the future contingencies will not be incurred.

8.5.3 Where Financial Assurance is required to ensure that the regulated party has sufficient funds to complete a project or program by a deadline, the Financial Assurance that is provided can be returned as the regulated party incurs the expenses and submits invoices. When returning Financial Assurance for a partially completed project, the Program Director should require the regulated party to provide an estimate of the remaining expenses and the Program Director must ensure that enough Financial Assurance is retained to cover the expenses that are still outstanding.

8.5.4 Returns or reductions from Financial Assurance cash funds should be initiated by the Program Director and authorized by the Environmental Assessment and Approvals Branch (EAAB) Director in an order under section 134 of the EPA and communicated to the Business and Fiscal Planning Branch who will return the Financial Assurance to the regulated party.

8.5.5 At the discretion of the Program Director, if surplus funds (the difference between the actual amount of Financial Assurance and the order or approval requirement of Financial Assurance) exist, funds can be returned to the regulated party upon request. The Program Director should be satisfied that the excess funds will not be needed in the future. The Business and Fiscal Planning Branch is to ensure that payments made to the regulated party are in accordance with appropriate Ministry and Government of Ontario guidelines, procedures and policies.

8.5.6 Section 134 Order for returns or reductions of Financial Assurance:

a) Must be issued when the Ministry returns Financial Assurance to regulated party;

b) Must specify reasons why all or partial Financial Assurance is being released;

c) Must specify regulated party's appealable rights and time frames;

d) Does not need to be posted on the Environmental Registry (not a prescribed instrument);

e) Is initiated and approved by the Program Director for non-cash accounts;

f) Is initiated by the Program Director and approved by the EAAB Director for cash accounts; and

g) Is accompanied by the Financial Assurance Refund/Disbursement Form (refer to Appendix I) approved by the EAAB Director for cash accounts.

8.5.7 The Program Director's correspondence to Business and Fiscal Planning Branch requesting to release or reduce Financial Assurance funds should be accompanied by a section 134 Order, and a Financial Assurance Refund/Disbursement Form. The templates are found in the Integrated Divisional System (IDS) database and can be modified by the Program Director on a case-by-case basis. The Program Director should then send the section 134 Order to the regulated party.

8.5.8 Business and Fiscal Planning Branch correspondence accompanying release of Financial Assurance will document that it is the responsibility of the regulated party to pay taxes on interest earned on cash Financial Assurance.

8.5.9 Once it is determined that Financial Assurance should be returned to the regulated party or the person or firm who issued the Financial Assurance, it should be returned to the regulated party within a reasonable time frame.

8.5.10 The Business and Fiscal Planning Branch will provide advice to the Program Director about the return or release of Financial Assurance.

8.5.11 Flow chart F4 in Appendix F outlines the necessary procedures to return Financial Assurance.

9. Responsibilities of Ministry Branches and Staff

9.1 The roles and responsibilities of the Program Director (who is usually a staff member in the Environmental Assessment and Approvals Branch or in Regional and District Offices) (Section 9.2), the Business and Fiscal Planning Branch (Section 9.3), the Regional and District Offices (Section 9.4), the Environmental Assessment and Approvals Branch (Section 9.5) and the Economic Analysis Section (Section 9.6).

9.1.1 Flow charts presented in Appendix F illustrate the primary responsibilities for the proper administration of obtaining, returning, converting non-cash Financial Assurance to cash and using Financial Assurance.

9.2 Program Director

9.2.1 The Program Director is generally employed in one of the following two Ministry branches or offices:

a) Regional Offices; and

b) Environmental Assessment and Approvals Branch (EAAB).

9.2.2 Ministry staff noted in Section 9.2.1 can solicit advice from the following Ministry divisions, branches or sections (or their equivalents):

a) Economic Analysis Section (EAS) in Ministry of Energy, as per a shared services agreement between the Ministry of the Environment and the Ministry of Energy;

b) Legal Services Branch (LSB);

c) Business and Fiscal Planning Branch (BFPB);

d) Environmental Sciences and Standards Division (ESSD);

e) Environmental Assessment and Approvals Branch (EAAB); and

f) Regional Offices.

9.2.3 The primary contact with regulated parties will be through the Program Director.

9.2.4 Where discussions are to take place between the Ministry and the regulated party, meetings and other direct contacts with the regulated party should be arranged by or through the Program Director and other staff as needed.

9.2.5 The principle responsibilities of the Program Director are to:

a) Write the conditions for Financial Assurance in the order or approval;

b) Issue order or approval with Financial Assurance conditions;

c) Deliver the order or approval to the regulated party;

d) Ensure that the Financial Assurance proposal and Financial Assurance amount has been received from the regulated party;

e) Ensure that copies of the Financial Assurance and supporting documents are sent to the Environmental Assessment and Approvals Branch in terms of an order and to the District Offices in terms of an approval for their information;

f) Ensure that the original Financial Assurance and supporting documents are sent to the Business and Fiscal Planning Branch for final review, verification and safekeeping;

g) Review Financial Assurance proposal to ensure all information items noted in Section 6.4 have been included in proposal and seek advice, if necessary, from Legal Services Branch and Economic Analysis Section;

h) Ensure that the Financial Assurance proposed and provided is sufficient to pay for compliance with terms and conditions in the relevant order or approval by determining whether the underlying cost estimates are reasonable and whether the Financial Assurance amounts are calculated according to this Guideline, with assistance from the Economic Analysis Section;

i) Review non-cash Financial Assurance documents to verify expiry dates, automatic renewal clauses, values, contract provisions and accessibility;

j) Ensure that cash Financial Assurance has been deposited in the Consolidated Revenue Fund;

k) Ensure that the Financial Assurance amount is amended annually or according to the Cumulative Financial Assurance Balance Schedule specified in the order or approval;

l) Ensure that the Business and Fiscal Planning Branch is informed of new accounts or specific new actions regarding existing accounts;

m) Ensure that all information in a new or updated Financial Assurance account is provided to the individual, section or office that maintain Financial Assurance databases;

n) According to the approval conditions, review the amount of the Financial Assurance in each active account to ensure that the amount of Financial Assurance is sufficient to cover any increases in expected capital and other one-time costs, or operating costs and any changes in other program requirements such as economic parameters;

o) Request and authorize conversion of non-cash form to cash (refer to Section 8.3);

p) Instruct Business and Fiscal Planning Branch to demand cash payment from issuing institution if letter of credit and bond are not renewed;

q) Request use of cash in a section 136 Order (refer to Section 8.4);

r) Ensure that all work done has been completed in a satisfactory manner before all or any amounts of the Financial Assurance can be returned to the regulated party;

s) Request and authorize returns or reductions in non-cash Financial Assurance in a section 134 Order (refer to Section 8.5);

t) Request returns or reductions in cash Financial Assurance in a section 134 Order (refer to Section 8.5);

u) Monitor periodically, review and report on active Financial Assurance accounts as required by Ministry management. Reports should include information on each account and should include, at a minimum, the following items:

- Name and identifiers (e.g., location, order or approval number, etc.) of the regulated party for each account;
- Type of facility or operation (e.g., landfill, steel mill, sewage or treatment facilities, etc.);
- Type of environmental problem or pollutant (e.g., hazardous waste, non-hazardous solid waste, air pollutants, industrial water pollution, PCB destruction, etc.);
- Type of legal instrument requiring Financial Assurance (e.g., type of order or approval issued);
- Amount of Financial Assurance provided;
- Form of Financial Assurance provided;
- Expiry date of the Financial Assurance requirement or form if applicable; (All non-cash instruments should have automatic renewal clauses. Some old existing forms may not have the clause. Flag accounts where financial institution or guarantor have issued forms without renewal clauses.)
- Payments into and out of each account, accrued interest, current balance of account for the trust fund within the Consolidated Revenue Fund;

- Cases where the Financial Assurance was called in (whether a non-cash Financial Assurance was just converted to cash or Financial Assurance was actually used); and
- Cases where Financial Assurance funds are used by the Ministry to fulfill the terms and conditions in an order or approval.

v) Conduct periodic reviews of Financial Assurance accounts which include but are not limited to the following appropriate steps:

- Obtain any Financial Assurance that has been required in orders or approvals;
- Obtain additional Financial Assurance where required;
- Ensure that time-limited, non-cash Financial Assurance has been properly renewed;
- Authorize the use of Financial Assurance if necessary; and
- Authorize the return of Financial Assurance to regulated parties where appropriate.

9.2.5.1 Where Program Director learns of, is informed of or is advised that a regulated party with active Financial Assurance accounts faces financial difficulties, such as:

a) The regulated party files for credit protection or bankruptcy;

b) The regulated party lays off employees to an unprecedented extent;

c) A bank notifies the Ministry that it will not renew the regulated party's letter of credit; or

d) A surety company notifies the Ministry that it will not renew a surety bond.

The Program Director should take the following steps, expeditiously:

a) As soon as possible, initiate conversion of non-cash Financial Assurance to cash;

b) Initiate any investigations necessary to verify evidence of the regulated party's impending insolvency. The Program Director should obtain assistance from the Economic Analysis Section for this task; and

c) Review sufficiency of the Financial Assurance for the site or establishment and if the amount of the Financial Assurance is determined to be insufficient, obtain as soon as possible, sufficient Financial Assurance in cash from the regulated party.

9.3 Business and Fiscal Planning Branch

9.3.1 Primary responsibilities of the Business and Fiscal Planning Branch (BFPB) are to:

a) Hold all Financial Assurances, including cash and original Financial Assurance documents, as well as supporting documents, for safekeeping;

b) Record data on all Financial Assurance accounts and maintain an electronic database of accounts. Coordinate and liaise with other databases such as the Integrated Divisional System (IDS) which maintain information regarding Financial Assurance;

c) Report on Financial Assurance accounts and statistics;

d) Review and verify that non-cash Financial Assurance forms and documents are still valid;

e) Review non-cash Financial Assurance forms for completeness to ensure form meets Ministry standards;

f) Monitor fluctuations of the value of Financial Assurance accounts as appropriate;

g) Set up accounts for new cash and converted Financial Assurances. Record to the Integrated Financial Information System (IFIS);

h) Record cash deposits and ensure that deposits and refunds are correctly reported to IFIS;

i) Prepare monthly reconciliation of cash Financial Assurances in IFIS;

j) Calculate and distribute yearly interest (calculated using the Tiered Rate offered by Ontario Financing Authority at Ministry of Finance) to individual cash Financial Assurance accounts. Send records to the Ministry of Finance for payment;

k) Return Financial Assurance to the regulated party as per the instructions of the Program Director;

l) Convert non-cash form to cash as per the instructions of the Program Director;

m) Document the responsibility of regulated party to pay taxes on interest earned on cash Financial Assurance in correspondence accompanying release of Financial Assurance funds;

n) Ensure that requested surplus payments (difference between the actual and required Financial Balance) are returned to the regulated party in accordance with appropriate Ministry and Government of Ontario guidelines, procedures and policies. If funds are to be returned, the Program Director will notify and instruct Business and Fiscal Planning Branch in writing to release funds;

o) Issue periodic reports as required by Ministry management. This report should include information on each account and should include, at a minimum, the information cited in Section 9.2.5, paragraph u);

p) Issue other reports requested by Ministry management and other government staff who work on Financial Assurance accounts; and

q) Provide financial guidance to the Program Director.

9.4 Regional and District Offices (R&DOs)

9.4.1 The primary responsibilities of the R&DOs are to:

a) Prepare Financial Assurance conditions in an order;

b) Review proposals for technical accuracy;

c) Send Financial Assurance proposals to Economic Analysis Section for review of economic parameters and Financial Assurance calculations;

d) Review Financial Assurance amounts and documents received from regulated party;

e) Send documents to Legal Services Branch for review, if necessary;

f) Send documents and cash to Business and Fiscal Planning Branch for safekeeping, and

g) Prepare periodic reports as required by Ministry management. The report should be prepared by the designated divisional lead on Financial Assurance and should include, but not be restricted to:

- The information cited in Section 9.2.5, paragraph u);
- Operational changes and developments, if any;
- Comments on problems with administration, implementation or other issues;
- Staff time devoted to Financial Assurance and to other related activities;
- Goals, targets and other indicators of progress and indicators of effectiveness; and
- Statements on Financial Assurance accounts and coverage.

9.5 Environmental Assessment and Approvals Branch (EAAB)

9.5.1 The primary responsibilities of the Financial Assurance Officer at EAAB are to:

a) Review existing approvals for landfills, sewage works, air, permits to take water to initiate Financial Assurance, where appropriate;

b) Analyze/monitor Financial Assurance accounts to ensure that when Financial Assurance is required in an order, approval or regulation that Financial Assurance has been provided to the Ministry;

c) Assist in preparing Financial Assurance conditions for approvals;

d) Ensure Financial Assurance accounts remain in compliance with terms and conditions noted in orders or approvals; including that regulated parties submit all required re-evaluations and annual Financial Assurance payments;

e) Review proposals for reasonableness and accuracy of cost estimates;

f) Assess standard forms of Financial Assurance for automatic renewal clauses;

g) Assess non-standard forms (value of bonds, marketable securities, shares, etc.) of Financial Assurance against fluctuations in market prices. If the values of the non-standard forms fall to a level less than the required value of the Financial Assurance, the Program Director should be informed that additional Financial Assurance must be provided in cash;

h) Administer procedures for obtaining Financial Assurance and handling documents (e.g., send documents to Economic Analysis Section, Legal Services Branch and Business and Fiscal Planning Branch for safekeeping);

i) Administer the procedures for converting non-cash Financial Assurance to cash once it has been identified that an active Financial Assurance account has financial difficulties;

j) Administer the procedures using Financial Assurance and for returning Financial Assurance;

k) Perform compliance audits of Financial Assurance accounts;

l) Maintain the Financial Assurance component of the Integrated Divisional System (IDS);

m) Make regular inquiries to the Superintendent of Deposit Institutions and the Superintendent of Insurance in the Ministry of Finance and to the Canadian Inspector General of Banks or similar institutions as to the status and solvency of the institutions that provide Financial Assurance;

n) Make regular inquiries to the Financial Services Commission of Ontario regarding the status and solvency of Credit Unions and Caisse Populaires which provide Financial Assurance; and

o) Provide financial advice and policy support.

9.6 Economic Analysis Section (EAS) in Ministry of Energy, as per a shared services agreement between the Ministry of the Environment and the Ministry of Energy

9.6.1 The responsibilities of the EAS with respect to Financial Assurance are to:

a) Contribute to updates of Financial Assurance Guideline and policies;

b) Review economic parameters and Financial Assurance calculations in the Financial Assurance proposal documents;

c) Provide advice to Ministry staff about interpretation of the Financial Assurance Guideline;

d) Provide advice to Ministry staff regarding appeals;

e) Provide advice to regulated parties; and

f) Conduct special studies as required such as the use of Financial Assurance or the effectiveness of the Financial Assurance program.

Appendix A

Compliance Cost Items to Estimate the Amount of Financial Assurance Required for Specific Orders, Approvals, Facilities and Activities

Compliance Cost Items to Estimate the Amount of Financial Assurance Required for Specific Orders, Approvals, Facilities and Activities

Introduction

This appendix is intended to help Ministry staff and regulated parties estimate the costs associated with compliance activities which can then be used to determine Financial Assurance amounts. Specific activities, technologies, practices and other cost components are suggested for each type of order or approval or for certain types of facilities that are listed in Section 4. Note that these activities and technologies are defined for cost estimation purposes only. Regulated parties are not obliged to use these specific technologies to comply with their own regulatory requirements. Indeed, regulated parties may use different technologies to produce their own estimates for Financial Assurance purposes. In any event, the procedures suggested in this appendix can be used to scrutinize and verify estimates provided by proponents.

As discussed in Section 6, at least two key types of costs must be provided for each program activity, facility, technology, etc.

(1) **Capital and other one-time costs:** Costs incurred for the purchase of equipment and installation of equipment, construction of buildings and other site improvements, including the costs for contract services, architect services, construction labour, laboratory testing, project management, etc.; incurred usually once during the project.

(2) **Recurring or annual costs:** Costs for operation, maintenance and monitoring of equipment, buildings and the site, including the costs for labour, materials, ongoing consultant services, monitoring, etc.; expressed on an annual basis.

Financial Assurance proposals that specify technologies, cost estimates, appropriate inflation and discounting procedures (where necessary) and Financial Assurance determinations are the responsibility of the approval applicants or recipients of orders with Financial Assurance conditions.

Relevant cost estimates are to be provided by the regulated party in their Financial Assurance proposal documents. However, Ministry staff should review the estimates for completeness, accuracy of computations, reasonableness of technical assumptions and site characteristics used in calculations such as relevant financial parameters and the contaminating life span of a landfill. Ministry staff should keep on file, or have access to, documentation concerning procedures, data, assumptions and computations to show how Financial Assurance amounts are determined for each Financial Assurance account.

Financial Assurance is **not** required for landfill sites and other facilities for which a municipality or the Crown is the responsible owner or operator.

A detailed example of the procedures and computations needed to determine Financial Assurance for a typical landfill subject to Ontario Regulation 232/98 is provided in Appendix H. A spreadsheet template for these calculations in either Microsoft Excel (Corel Quattro Pro accepted) can be obtained from the:

a) Financial Assurance Officer - Environmental Assessment and Approvals Branch, Ministry of the Environment, or
b) Economic Analysis Section, Ministry of Energy.

Users of this Guideline are reminded that the purposes of Financial Assurance are to ensure that sufficient funds are available to comply with conditions of a regulation, order or approval at some near or distant future point in time, including, but not restricted to, decommissioning, clean-up, rehabilitation and perpetual care.

Financial Assurance may not be retained by the government as a penalty. However, Financial Assurance may be kept by the Ministry until the regulated party has completed (and paid for) all compliance activities or the Financial Assurance has been used for these purposes. When the Program Director is satisfied that Financial Assurance is no longer needed for a particular site, facility or purpose, it can be returned to the regulated party.

Cost items that form the basis of Financial Assurance amounts are identified and discussed for each of the various types of facilities, approvals and orders which were listed in Section 6. To the extent possible, the types of facilities, approvals, etc. are listed below in the same order as in Section 6.

Facilities, approvals and orders where the planning period is less than four years or when there is no known future date for closure, clean-up or remediation expenditures (A.1 - A.12)

A.1 Private Transfer Stations and Private Waste Processing Sites

A.1.1 Financial Assurance to be provided for these facilities is equal to the total cost of removing, transporting and disposing of any materials left on site if the owners or operators cease operations for any reason and could not, or would not, clean up the site.

A.1.2 The following items related to a transfer station or waste processing facility must be enumerated or estimated:

a) quantity of total waste allowed on the site that will not be sold or removed prior to closure, in tonnes or cubic metres. Disaggregate by type of waste where possible, e.g., tonnes of contaminated wood;

b) quantity of total materials allowed on the site for which the owner has provided documentation from other parties who will remove said materials at no cost to the Ministry, in tonnes or cubic metres, e.g., tonnes of broken asphalt;

c) the total quantities of all materials noted in a) and b) above must not exceed the maximum quantity or capacity of all materials allowed on the site by the certificate of approval;

d) structures and other items on site that have to be demolished and removed to comply with the certificate of approval;

e) movable equipment items that can and cannot be sold for scrap;

f) security devices that must be installed permanently or temporarily, e.g., metres of perimeter fencing, gates, alarms, etc.;

g) amount of contaminated soil on the site that must be excavated and removed, in tonnes or cubic metres; and

h) distance, in kilometres, to final disposal site(s).

A.1.3 The following cost items should be obtained, determined or estimated:

a) cost per unit or job of any demolition required;

b) unit costs of loading each type of waste, demolition rubble, contaminated soil or equipment that must be sent for disposal, e.g., $/tonne or cubic metre;

c) unit costs of any required treatment activities, e.g., soil decontamination;

d) unit costs of transporting each type of waste, demolition rubble, contaminated soil or equipment that must be sent for disposal, e.g., $/tonne, cubic metre/km,

e) unit cost (“tipping fee”) for disposing of each type of waste, demolition rubble, contaminated soil or equipment in an approved disposal site, e.g., $/tonne, cubic metre; and

f) costs of security devices as needed.

These costs must reflect the costs of a third party to undertake all work associated with managing and carrying out the activities listed in A.1.2.

A.1.4 In addition, the following cost items may be relevant for some facilities:

a) management, supervisory, administrative costs, expressed as a percentage of the sum of costs listed in A.1.5. Evidence of the need and percentage used should be provided;

b) contingency costs may be required if the estimates for cost items in A.1.5 are uncertain. Contingency costs are also expressed as a percentage (e.g., 10 to 15% of total costs) of the sum of costs listed in A.1.5;

c) any other activities necessary to implement long-term care provisions, if applicable;

d) any other steps and activities necessary to complete site rehabilitation.

A.1.5 Financial Assurance for these facilities must include the sum of:

a) total cost of demolition, where required;

b) total cost of loading all waste, demolition, contaminated soil and equipment on to transport vehicles, e.g., quantity of contaminated wood x unit cost of loading contaminated wood;

c) total cost of transporting all waste, demolition, contaminated soil and equipment to disposal sites, e.g., quantity of contaminated wood x cost/km of transporting contaminated wood x km to disposal site;

d) total cost of disposing all waste, demolition, contaminated soil and equipment in approved disposal sites, e.g., quantity of contaminated wood x unit cost of disposal (i.e., "tipping fee");

e) total cost of treating any of the wastes prior to final disposal, e.g., quantity of contaminated soil x unit cost of decontamination; and

f) total cost of any security devices or installations required.

A.1.6 If conditions in the certificate of approval require actions to prevent potential off-site contamination arising from operation of the site, the costs of these actions should be estimated. It would be prudent to obtain Financial Assurance for these actions until the owner provides evidence that the actions have been completed.

A.1.7 Financial Assurance for the above-noted cost items should be obtained by the Program Director before the commencement of operations or as otherwise required by the Program Director.

A.2 Private Waste Management (Haulage) Systems Which Carry Wastes

A.2.1 In accordance with the document, *Guide for Applying for Approval of a Waste Management System*, issued November 1999 by the Environmental Assessment and Approvals Branch of the Ministry of the Environment:

a) each biomedical waste hauler is required to provide "an Irrevocable Letter of Credit in the minimum amount of $50,000..." which "...is to be posted with the Ministry of the Environment," and

b) each PCB waste hauler must provide “An Irrevocable Letter of Credit in the Amount of $100,000...” which “...must be sent to the Director of the Environmental Assessment and Approvals Branch prior to the operations and issuance of a PCB waste management systems.” *(sic)*

A.2.2 The Financial Assurance amount for biomedical waste haulers are based on:

a) the sized (dimensions) of the biomedical transportation container utilized, and

b) the number of containers required to reach maximum fleet capacity.

A.2.3 For haulers of any other material (e.g., hazardous subject waste, caustic chemicals) for which Financial Assurance is deemed necessary (i.e., criteria in Section 4.4 apply), the amount should be equal to 100% of the estimated costs of cleaning up, hauling away and disposing of all debris and any contaminated soil from a spill or upset from the largest vehicle owned by the regulated party (hauler).

A.2.4 Financial Assurance is not normally obtained from haulers of biosolids (processed organic wastes and hauled sewage). Financial Assurance is not required for sites at which processed organic waste or hauled sewage are spread. Spreading rates and total amount of biosolids received at a given site are limited by the certificate of approval.

A.2.5 Additional costs on which Financial Assurance amounts for haulers of materials not subject to the *Guide for Applying for Approval of a Waste Management System* may be based on, but not restricted to:

a) loading all debris and contaminated soil from a spill;

b) transporting debris and soil to the nearest approved disposal site;

c) disposing of all debris and contaminated soil in an approved disposal site;

d) where necessary, the cost of provision of alternate water supplies in accordance with subsection 132 (1) (b), Part XII, EPA;

e) estimates are based on spilling a load of PCBs or biomedical waste from the largest vehicle owned by the regulated party; and

f) compensation for out-of-pocket expenses by damaged parties where authorized.

A.2.6 The procedures and input data for estimating the predetermined Financial Assurance amounts noted in the *Guide for Applying for Approval of a Waste Management System* should be reviewed and updated by staff every five years in order to ensure sufficiency of Financial Assurance and to defend amounts required in appeals.

A.3 Private Used Tire Storage or Disposal Facilities Which Contain More Than 5,000 Tire Units

A.3.1 Financial Assurance for these sites is equal to the total costs of loading, transporting and disposing of tires to approved sites or uses.

A.3.2 All cost items and computational steps and procedures for this type of site are similar to those for transfer stations and waste processing facilities listed in A.1.

A.4 Regulation 352 - Mobile PCB Destruction Facilities

A.4.1 Regulation 352 - Mobile PCB Destruction Facilities, requires that applicants for PCB destruction facility approvals provide the following predetermined amounts of Financial Assurance:

a) $50,000 for each Class 1 mobile PCB destruction facility waste disposal site; and

b) $50,000 for each Class 2 mobile PCB destruction facility waste management system (hauler).

A.4.2 The costs on which these predetermined amounts are based are not revealed in the regulation. However, a review and verification of these costs should be undertaken, at least, every five years in order to ensure sufficiency of the Financial Assurance and to verify the Financial Assurance estimates.

A.5 PCB Storage Sites Established in Accordance with Written Director's Instructions under Regulation 362 - Waste Management – PCBs

A.5.1 Financial Assurance for PCB storage facilities should equal 100% of the total one-time capital costs of removing the total allowable capacity of the PCBs to a licensed destruction facility plus the charges for destroying all of the PCBs in the facility.

A.6 Approvals under Section 53, OWRA Including Private Communal Sewage Systems and Sewage Works in Unorganized or Organized Areas Without a Municipal Government Agency Agreement to Take over the System

A.6.1 The amount of Financial Assurance required should be equal to 100% of three years of undiscounted operating costs plus 15% of the capital costs sufficient to provide funds for upgrading or clean-up that may be required after a default and for temporary operation by the Ministry until a municipality or another local organization takes over operations.

A.6.2 Key cost items include, but are not restricted to:

a) one-time capital items such as replacement of pipes, pumps and controls; construction of tanks; electrical equipment; construction of structures; installation of all equipment, etc. which are sized appropriately; and

b) recurring, annual operating expenses include labour, power or fuel, chemicals, repair and maintenance expenses and contract expenses for lab work. These costs may be obtained directly from engineering consultants or based on the volume capacity of the facility.

A.7 Approvals under Section 9, EPA

A.7.1 Approvals under section 9, EPA including (but not limited to) those that contain conditions associated with:

a) specific abatement actions that contain deadlines;

b) the storage of subject waste materials from air pollution control equipment;

c) equipment used in the mobile in-situ chemical oxidation process; and

d) back-up control equipment.

A.7.2 Financial Assurance should be calculated as follows:

a) for specific abatement actions that contain deadlines, the amount of Financial Assurance would be 100% of the capital and all recurring costs to implement all abatement requirements;

b) for the storage of subject waste materials from air pollution control equipment, the amount of Financial Assurance would be 100% of the estimated cost to remove the subject waste from the site and dispose of it in accordance with Ministry standards;

c) for equipment used in the mobile in-situ chemical oxidation process, the amount of Financial Assurance would be based on the number of sites being operated under the certificate of approval, or some other basis deemed acceptable by the Program Director; and

d) where the compliance projects are to be completed within four years, the amount of Financial Assurance should be 100% of the estimated one-time (capital) costs of replacing the air pollution control equipment with back-up control equipment that is known to control the emissions in question to an acceptable degree as required by the Program Director.

A.7.3 Cost items should include capital and one-time design and equipment items, appropriate sizing according to gas flows, temperature and other factors that affect capital costs. This information should be provided by engineering consultants that are hired by approval applicants.

A.8 Approvals for Operations Which Discharge into Surface Waters Subject to Section 53, OWRA

A.8.1 Financial Assurance can be required to ensure that compliance with the terms and conditions of an approval are achieved by a specified date.

A.8.2 Cost estimates of the required abatement or preventative systems and activities should be provided by the regulated party. If such estimates are not submitted, the Program Director should issue an order to require that the regulated party provide these estimates. The issuing Program Director should confer with the Economic Analysis Section regarding the kind of cost data and other information that should be specified in the order and obtained from the regulated party.

A.8.3 Financial Assurance would normally be equal to 100% of the capital costs of implementing the required abatement or prevention systems. If costs are to be incurred over four or more years, the recommended amount of Financial Assurance is equal to the present value of capital and other one-time costs, plus the total annual recurring costs for the entire period.

A.9 Permits to Take Water under Section 34, OWRA

A.9.1 The amount of Financial Assurance for a permit to take water should be 100% of the least-cost, technically acceptable method of supplying any parties who are adversely affected, with domestic water by other means, including delivery by truck.

A.9.2 If truck delivery is the basis for cost estimation, water and delivery costs should be estimated for a minimum of two years.

A.9.3 If there is evidence or experience that a new well or pipeline would be the only feasible replacement option, the estimated capital cost of the installation plus two years of undiscounted operating costs should be provided as Financial Assurance.

A.9.4 The cost items for truck delivery include:

a) the quantity of bottled water to be delivered to each affected party each day or week;

b) the price of the bottled water;

c) the average distance driven for deliveries each week or month; and

d) truck operating costs per km, etc.

A.9.5 Information about activities and cost items for constructing new wells or communal hook-ups to existing systems may be obtained from equipment venders and municipal works departments.

A.10 Orders to Undertake Industrial Abatement Programs under Section 18, EPA

A.10.1 Financial Assurance may be required as a condition of an order to ensure that:

a) sufficient funds for compliance are available, and

b) compliance is achieved by the agreed-to deadline.

A.10.2 Cost estimates for abatement or preventative measures ordered should be obtained from the regulated party by voluntary means or by means of conditions in the order served. Staff should refer to:

a) the Ministry Guideline F-14, Economic Analyses of Control Documents on Private Sector Enterprises and Municipal Projects, and

b) the Economic Analysis Section (Ministry of Energy) to help staff define the cost information that should be specified in the order.

A.10.3 The amount of Financial Assurance should be equal to 100% of the total undiscounted capital cost of abatement or prevention systems necessary to satisfy or complete the conditions of the order. Future contingency costs should also be estimated. If there is more than one technical option available to achieve the requirements of the order, the least-cost option can be used as the basis of the Financial Assurance amount.

A.10.4 If the implementation period is to extend longer than four years, costs to be incurred in the 5th and subsequent years may be discounted using the preferred discount rate indicated in Section 6. The Financial Assurance amount is equal to the sum of all expenditures over the period of installation of equipment and facilities.

A.10.5 Financial Assurance provided as a condition of an order for abatement or prevention programs can be used to pay invoices as costs are incurred so that the total Financial Assurance balance can be reduced as the work is completed. In this context, Financial Assurance will provide the regulated party with a financial incentive to implement compliance actions in a timely manner. Ministry staff should review Financial Assurance balances and estimated future expenditures every six months to ensure that remaining Financial Assurance is sufficient.

A.11 Orders to Require Decommissioning and Remediation of Contaminated Sites

A.11.1 An order that requires decommissioning and remediation of a contaminated site may also include conditions to require Financial Assurance in the certificate of approval. Financial Assurance should be required where one or more of the criteria noted in Section 4.4 paragraph a) of the Guideline apply. It is presumed that such a site will be remediated so that the site may be used for new construction or other purposes.

A.11.2 The amount of Financial Assurance should be equal to 100% of the one-time capital costs for decommissioning and remediation to bring the site into compliance with the terms and conditions of the order and local zoning by-laws. Cost estimates should be made under the assumption that the work will be carried out by a third party contractor.

A.11.3 The requirement to estimate costs of the above-noted activities and to report them to the Program Director should be specified as conditions in the order.

A.11.4 Cost items associated with decommissioning and rehabilitation include:

a) engineering and design,

b) soil testing,

c) site preparation and security (fencing),

d) excavation, hauling, disposal fees,

e) contaminated soil processing (if necessary), and

f) insurance and inspections.

A.12 Orders Involving Storage of Subject Wastes under Regulation 347

A.12.1 Financial Assurance to be provided for these facilities is equal to the total cost of removing, transporting and disposing of any materials left on site if the owners or operators ceased operations for any reason and could not, or would not, clean up the site. For purposes of Financial Assurance, these types of sites are similar to those noted in A.1 above.

A.12.2 Relevant information items needed to estimate costs include:

a) quantity of total waste allowed on the site, in tonnes or cubic metres. Disaggregate by type of waste where necessary;

b) movable equipment items that can and cannot be sold for scrap;

c) security devices that must be installed permanently or temporarily, e.g., metres of perimeter fencing, gates, alarms, etc.;

d) the amount of contaminated soil on the site, if any, that must be excavated and removed, in tonnes or cubic metres; and

e) distance, in kilometres, to final disposal site(s).

A.12.3 The following cost items should be obtained, determined or estimated:

a) unit costs of loading each type of waste and contaminated soil or equipment that must be sent for disposal, e.g., $/tonne or cubic metre;

b) unit costs of any required treatment activities, e.g., soil decontamination;

c) unit costs of transporting each type of waste, contaminated soil or equipment that must be sent for disposal, e.g., $/tonne, cubic metre/km;

d) unit cost ("tipping fee") for disposing of each type of waste in an approved disposal site, e.g., $/tonne, cubic metre; and

e) costs of security devices, as needed.

These costs must reflect the costs of contracting a third party to undertake all work associated with managing and carrying out the activities listed in A.12.2.

A.12.4 Financial Assurance for these facilities must consist of the sum of:

a) total cost of loading all waste, contaminated soil and equipment on to transport vehicles;

b) total cost of transporting all waste, contaminated soil and equipment to disposal sites;

c) total cost of disposing all waste, contaminated soil and equipment in approved disposal sites;

d) total cost of treating any of the wastes prior to final disposal, e.g., quantity of contaminated soil x unit cost of decontamination; and

e) total cost of any security devices or installations needed.

Estimating Financial Assurance when the planning period is four or more years or when there is a known future date for closure, clean-up or remediation expenditures (A.13 - A.16)

A.13 Private Municipal Waste Landfilling Sites

A.13.1 Financial Assurance requirements for private sector landfill sites should follow Ontario Regulation 232/98 - Landfilling Sites when:

a) the site came into existence on or after August 1, 1998 and was intended, at the time it came into existence, to have a total waste disposal volume of more than 40,000 cubic metres and to accept only municipal waste for disposal;

b) the site is being altered, enlarged or extended on or after August 1, 1998 so that, after alteration, the site's total waste disposal volume will exceed 40,000 cubic metres and will accept only municipal waste for disposal; and

c) where a landfill is subject to Ontario Regulation 232/98, the amount of Financial Assurance to be provided should be equal to the:

   i) present value, at the estimated date of closure, of the costs of planned closure for the largest area that will require final cover,

   ii) present value of post-closure care for the entire area of the site for the entire duration of the contaminating life span of the facility, and

iii) contingency costs for the entire area of the site. A numerical example is presented in Appendix H.

A.13.2 Costs of planned closure of the largest area that will require final cover at the end or the operating life of a landfill site include, but are not restricted to, the following activities, tasks, and parameters:

a) grading, final cover and landscaping;

b) construction of security fences and associated devices, roads;

c) installation of purge wells, test wells for monitoring leachate;

d) quantity and haul distances of cover material needed;

e) leachate and gas collection and treatment facilities if included in the site closure plan or if specified in the approval;

f) any other required remediation activities.

Financial Assurance for planned closure is not required if the filled portions of the site are closed properly within five years, or earlier.

A.13.3 Expected post-closure care, maintenance and monitoring activities over the entire area of the landfill that contains waste plus any buffer areas and lands that contain leachate and/or gas collection and treatment facilities, over the contaminating life span of the site, include, but are not restricted to, the following activities and tasks:

a) security;

b) maintenance of leachate monitoring wells;

c) sample collection, transportation and testing of leachate and off-gasses;

d) care and maintenance of the final cover and landscaping;

e) data reporting and storage of gas and leachate samples;

f) construction and maintenance of any other facilities mandated by an order or approval;

g) operation of vehicles, structures or equipment;

h) consulting charges;

i) replacement of any capital equipment (pipes, pumps, structures, wells, etc.) over the contaminating life span; and

j) labour charges based on person-days or person-years of effort required for each activity, classification of employees needed to do the work.

A.13.4 Financial Assurance also includes an additional amount for contingency costs. This contingency cost component is determined by a formula provided in Ontario Regulation 232/98:

$$F = \$0.50 \times W \times (I_2 \div I_1)$$

where,

F = the amount of the Financial Assurance,

W = the number of tonnes of waste that have been deposited in the landfilling site at the time the amount of Financial Assurance is calculated,

I_1 = the 1997 Annual Average Non-Residential Building Construction Price Index for Toronto, determined with reference to the same base year as is applicable to I_2, as published by Statistics Canada, Catalogue 62-007,

I_2 = the most recent Annual Average Non-Residential Building Construction Price Index for Toronto available at the time the amount of the Financial Assurance is calculated, as published by Statistics Canada, Catalogue 62-007.

As noted, the contingency cost amount is adjusted each year by the tonnes of waste deposited and by the Non-Residential Building Construction Price Index for Toronto.

A.13.5 Financial Assurance for a landfill site that has a total waste volume less than 40,000 cubic metres, or has been operating before August 1, 1998 may, at the discretion of the Program Director, be based on technologies and procedures that differ from those specified in Ontario Regulation 232/98. These alternative procedures are noted in A.13.6.

A.13.6 Ontario Regulation 232/98 is the preferred method of calculating Financial Assurance and is mandatory for sites which have been established on or after August 1, 1998 with a capacity over 40,000 cubic metres. The Program Director has the discretion to require other methods for calculating Financial Assurance as conditions of a certificate of approval. Therefore, for landfill sites that began operation before August 1, 1998 or are under 40,000 cubic metres capacity, the Program Director may direct that Financial Assurance be derived from the costs of emergency and planned closure, post-closure and contingency activities described below.

A.13.6.1 Emergency closure means that a site is closed prior to the planned closure date for some reason. For emergency closure estimates, the filled area to be covered and rehabilitated each year is equal to the proportion of the site that is filled each year. Emergency closure costs include, but are not restricted to, the following activities, tasks, and parameters:

a) grading, final cover and landscaping;

b) construction of security fences and associated devices, roads;

c) installation of purge wells, test wells for monitoring leachate;

d) quantity and haul distances of cover material needed; and

e) any other required remediation activities.

Emergency closure amounts may be updated each time Financial Assurance is reviewed in order to account for the expanded landfill use.

A.13.6.2 Planned closure generally occurs when the landfill reaches approved capacity. The cost estimates are based on the largest area that will require final cover at the end of the operating period of a landfill site. Cost items include, but are not restricted to, the following activities and tasks:

a) grading, final cover and landscaping;

b) construction of security fences and associated devices, roads;

c) installation of purge wells, test wells for monitoring leachate;

d) quantity and haul distances of cover material needed; and

e) any other required remediation activities.

Financial Assurance amount for planned closure replaces Financial Assurance for emergency closure five years before the planned final closure of the site.

A.13.6.3 Expected post-closure care, maintenance and monitoring activities over the entire area of the landfill that contains waste plus any buffer areas and lands that contain leachate and/or gas collection and treatment facilities. The time frame of post-closure care, maintenance and monitoring extends from the date of closure to the end of the contaminating life span of the site. Cost items include, but are not restricted to, the following activities and tasks:

a) security;

b) maintenance of leachate monitoring wells;

c) sample collection, transportation and testing of leachate and off-gasses;

d) care and maintenance of the final cover and landscaping;

e) data reporting and storage of gas and leachate samples;

f) construction and maintenance of any other facilities mandated by an order or approval;

g) operation of vehicles, structures or equipment;

h) consulting charges;

i) replacement of any capital equipment (pipes, pumps, structures, wells, etc.) over the contaminating life span; and

j) labour charges based on person-days or person-years of effort required for each activity, classification of employees needed to do the work.

A.13.6.4 Contingency costs consist of costs of potential leachate and gas collection and treatment facilities. Cost of repairing leaks in an impermeable liner under the landfill may also be included as a contingency as per conditions in the certificate of approval. The amount of Financial Assurance should equal the estimated one-time capital costs plus at least one year's operating costs.

A.13.6.5 During the operating life of a landfill, the total Financial Assurance for sites established before 1998 would be the sum of Financial Assurance for emergency closure, post-closure care and maintenance and contingency costs.

A.13.6.6 At least five years prior to closure, the total amount of Financial Assurance should be provided including the sum of planned closure costs, the present value of post-closure care and maintenance costs over the contaminating life span of the site and contingency costs based on leachate and gas collection and treatment and repair of impermeable liners as specified in the certificate of approval.

A.13.7 Irrespective of when the landfill operation began, the minimum contaminating life span for landfills is 25 years for purposes of discounting.

A.13.8 Not withstanding Ontario Regulation 232/98, relevant cost estimates should be updated every three years or as otherwise required by the Program Director.

A.14 Incineration Facilities

A.14.1 Financial Assurance for incinerators is for the purpose of funding the decommissioning of the facility. Since decommissioning would take place more than four years after a plant begins operation, Financial Assurance for the facility would equal the present value of all decommissioning costs.

A.14.2 Decommissioning costs include:

a) removal of all equipment, machinery and fixtures which can be sold;

b) demolition of all structures;

c) loading of all demolition debris and machinery that cannot be sold;

d) transporting all demolition debris to an approved disposal facility;

e) disposal of all demolition debris in an approved facility;

f) decontamination of soil if needed; and

g) removal of contaminated soil to an approved disposal facility.

A.14.3 Cost estimates made at the outset of the facility's operating life will be very uncertain. Assumptions must be clearly defined. Updates should be made at least every three years or at the direction of the Program Director.

A.15 Approvals under Section 53, OWRA for Industrial and Milling Activities That Generate Tailings or Ash

A.15.1 Financial Assurance may be required to finance site closure and rehabilitation of tailings, slag or other waste material storage areas and for long-term care. The amount of Financial Assurance required should include 100% of the present value (at the time of closure) of the total costs of planned closure and rehabilitation activities, plus costs of long-term monitoring, maintenance and contingency plans as required by the Program Director.

A.15.2 Present value computational procedures are similar to those for landfills. The time period for present value calculations is the contaminating life span of the disposal facility or a time period that is otherwise acceptable to the Program Director.

A.15.3 If the regulated party is a mining company under the authority of the *Mining Act*, it may have provided Financial Assurance to the Ministry of Northern Development and Mines (MNDM) to finance the firm's site closure plan. If a mining operation is issued an order or approval, Ministry of the Environment staff should confer with the "mines group" of MNDM in Sudbury to ensure that sufficient Financial Assurance has been provided to pay for compliance costs of Ministry of the Environment requirements in addition to the provisions of the site closure plan. If Financial Assurance for site closure will not cover the costs of Ministry of the Environment requirements, additional Financial Assurance should be obtained by MNDM.

A.15.4 For disposal of ash, tailings, slag or other solids by non-mining industrial facilities, the amount of Financial Assurance required should include, but not be restricted to 100% of the present value of:

a) the total costs, at the time of closure, of planned closure and rehabilitation activities as specified in the approval, plus

b) costs of long-term monitoring, maintenance and contingency plans as required by the Program Director.

Present value computational procedures are similar to those for landfills. Spreadsheet templates shown in Appendix H can easily be adapted for this application. The time period for present value calculations is the contaminating life span of the disposal facility or a time period that is specified by the Program Director.

A.15.5 For non-mining industrial facilities that generate piles of ash or other solid waste materials, the activities and cost items of environmentally acceptable management and disposal for these facilities include:

a) site preparation (including area of site, cutting timber from the disposal area, grading and containment works);

b) cover (as needed) grading and re-vegetation of disposal area;

c) construction of containment dams or berms; and

d) long-term monitoring and maintenance of dams, leachate treatment facilities, leachate volumes and quality and ground water quality.

A.15.6 As with landfills, the amount of Financial Assurance on deposit each year should be increased so that the amount of money accumulated by the time the disposal facility is closed will be sufficient to pay for post-closure care. The quantity and/or area of waste materials that are generated each year should be monitored so that sufficient funds will be available to cover long-term care from the time that the facility closes to the end of the contaminating life span or the time period agreed to by the Program Director.

A.16 Approvals under Section 53, OWRA for Sewage Works That Generate Waste Materials (Sludges) That are Stored and Remain on the Site until and after Decommissioning

A.16.1 Assuming the Financial Assurance is for the costs of the long-term storage and maintenance of sludges and other waste materials on site, follow procedures for a landfill site subject to Ontario Regulation 232/98.

A.16.2 The Financial Assurance amount to be provided is equal to the sum of the present values of the total one-time (capital) and recurring costs for:

a) closure;

b) long-term post-closure care; and

c) the Financial Assurance amount for contingency costs as of the anticipated date of closure, as required by the Program Director, in dollars current at that date.

A.16.3 The time period for present value calculations should be the contaminating life span of the sludge deposits of the disposal facility or a time period that is acceptable to the Program Director.

A.16.4 As with landfills, the amount of Financial Assurance on deposit each year should be increased so that the amount of money accumulated by the time the disposal facility is closed will be sufficient to pay for post-closure care. The quantity and/or area of waste materials that are generated each year should be monitored so that sufficient funds will be available to cover long-term care from the time that the facility closes to the end of the contaminating life span or the time period agreed to by the Program Director.

A.16.5 If the waste materials are to be removed from the site upon decommissioning, the amount of Financial Assurance should be based on the costs of loading, hauling and disposing of the waste solids, similar to the costs associated with a transfer or waste processing facility. All relevant clean-up requirements that are to be included should be noted in the certificate of approval.

Appendix B

Part XII ─ Financial Assurance, Environmental Protection Act

PART XII
FINANCIAL ASSURANCE

Definitions, Part XII

131. In this Part,

"approval" means program approval, certificate of approval or provisional certificate of approval, and includes a permit or approval issued by a Director under the Ontario Water *Resources Act*, but does not include an approval under Part X of this Act; ("autorisation")

"bank" means a bank named in Schedule I or Schedule II to the *Bank Act* (Canada); ("banque")

"environmental measures" means one or more of the measures set out in clauses 132 (1) (a) to (c) or 132 (1.1) (a) to (c); ("mesures d'ordre environnemental")

"financial assurance" means one or more of,

(a) cash, in the amount specified in the approval, order or certificate of property use,

(b) a letter of credit from a bank, in the amount and terms specified in the approval, order or certificate of property use,

(c) negotiable securities issued or guaranteed by the Government of Ontario or the Government of Canada in the amount specified in the approval, order or certificate of property use,

(d) a personal bond accompanied by collateral security, each in the form, terms and amount specified in the approval, order or certificate of property use,

(e) the bond of an insurer licensed under the *Insurance Act* to write surety and fidelity insurance in the form, terms and amount specified in the approval, order or certificate of property use,

(f) a bond of a guarantor, other than an insurer referred to in clause (e), accompanied by collateral security, each in the form, terms and amount specified in the approval, order or certificate of property use,

(g) an agreement, in the form and terms specified in the approval, order or certificate of property use, and

(h) an agreement, in the form and terms prescribed by the regulations; ("garantie financière")

"order" means an order by the Director under this Act, and includes an order, notice, direction, requirement or report made by a Director under the *Ontario Water Resources Act*, but does not include an order under section 136 (order for performance of environmental measures) of this Act; ("arrêté") "works" means an activity, facility, thing, undertaking or site in respect of which an approval or order is issued. ("travaux") R.S.O. 1990, c. E.19, s. 131; 1993, c. 27, Sched.; 1997, c. 19, s. 34; 2001, c. 17, s. 2 (6, 7).

Financial assurance

Approval or order

132. (1) The Director may include in an approval or order in respect of a works a requirement that the person to whom the approval is issued or the order is directed provide financial assurance to the Crown in right of Ontario for any one or more of,

(a) the performance of any action specified in the approval or order;

(b) the provision of temporary or permanent alternate water supplies to replace those that the Director has reasonable and probable grounds to believe are or are likely to be contaminated or otherwise interfered with by the works to which the approval or order is related; and

(c) measures appropriate to prevent adverse effects upon and following the cessation or closing of the works. R.S.O. 1990, c. E.19, s. 132 (1); 2005, c. 12, s. 1 (22).

Certificate of property use

(1.1) The Director may include in a certificate of property use a requirement that the person to whom the certificate is issued provide financial assurance to the Crown in right of Ontario for any one or more of,

(a) the performance of any action specified in the certificate of property use;

(b) the provision of temporary or permanent alternate water supplies to replace those that the Director has reasonable and probable grounds to believe are or are likely to be contaminated or otherwise interfered with by a contaminant on, in or under the property to which the certificate of property use relates; and

(c) measures appropriate to prevent adverse effects in respect of the property to which the certificate of property use relates. 2001, c. 17, s. 2 (8); 2005, c. 12, s. 1 (23).

Changes in amount of financial assurance

(2) A requirement under subsection (1) or (1.1) may provide that the financial assurance may be provided, reduced or released in stages specified in the approval, order or certificate of property use. 2001, c. 17, s. 2 (9).

Amendment of approval, order or certificate of property use

(3) The Director may amend an approval, order or certificate of property use to change a requirement as to financial assurance contained in the approval, order or certificate of property use. 2001, c. 17, s. 2 (9).

Failure to provide financial assurance

133. (1) Failure to provide financial assurance specified in an approval or in accordance with a stage specified in an approval is grounds for revocation of the approval and for an order in writing by the Director prohibiting or restricting the carrying on, operation or use of the works in respect of which the financial assurance is required. R.S.O. 1990, c. E.19, s. 133 (1).

Idem, order

(2) Failure to provide financial assurance specified in an order or in accordance with a stage specified in an order is grounds for an order in writing by the Director prohibiting or restricting the carrying on, operation or use of the works in respect of which the financial assurance is required. R.S.O. 1990, c. E.19, s. 133 (2).

Same, certificate of property use

(3) Failure to provide financial assurance specified in a certificate of property use or in accordance with a stage specified in a certificate of property use is grounds for an order in writing by the Director prohibiting or restricting the use of the property to which the certificate of property use relates. 2001, c. 17, s. 2 (10).

Return or release of financial assurance

134. (1) Upon request, part or all of the financial assurance given in respect of a works or certificate of property use may be returned or released pursuant to an order in writing by the Director. R.S.O. 1990, c. E.19, s. 134 (1); 2001, c. 17, s. 2 (11).

Grounds for order

(2) The Director may make an order mentioned in subsection (1) if satisfied that the financial assurance returned or released is not required in respect of the works or certificate of property use. R.S.O. 1990, c. E.19, s. 134 (2); 2001, c. 17, s. 2 (12).

Continuation of financial assurance

135. The Director may convert a financial assurance to cash to be held by the Crown to the same purposes as the financial assurance or otherwise realize the financial assurance unless the financial assurance is renewed at least thirty days before it would otherwise expire. R.S.O. 1990, c. E.19, s. 135.

Order for use of financial assurance

136. (1) In the circumstances set out in subsection (2), the Director by order may require the performance of environmental measures for which the Crown holds financial assurance and may require the use of the financial assurance for the performance of the environmental measures. R.S.O. 1990, c. E.19, s. 136 (1).

Basis for order

(2) The Director may make an order mentioned in subsection (1) if the Director has reasonable and probable ground to believe that any environmental measure required by the approval, order or certificate of property use in respect of which the financial assurance was

given has not been or will not be carried out in accordance with the requirement. R.S.O. 1990, c. E.19, s. 136 (2); 2001, c. 17, s. 2 (13).

Parties affected

(3) An order under this section shall be directed to,

(a) the person to whom the approval, order or certificate of property use was issued or any other person who is bound by the approval, order or certificate of property use; and

(b) any person that to the knowledge of the Director has provided the financial assurance for or on behalf of a person referred to in clause (a), or any successor or assignee of a person that to the knowledge of the Director has provided the financial assurance for or on behalf of a person referred to in clause (a). 2001, c. 17, s. 2 (14).

Performance

(4) Upon the issuance of an order by the Director under subsection (1), the Crown may,

(a) use any cash;

(b) realize any bond or other form of security, and use the money derived therefrom; and

(c) enforce any agreement,

provided or obtained as the financial assurance for the performance of the environmental measures and may carry out the environmental measures. R.S.O. 1990, c. E.19, s. 136 (4).

* * * * *

Regulations relating to Part XII

176. (9) The Lieutenant Governor in Council may make regulations relating to Part XII prescribing requirements for financial assurance in respect of the classes of approvals, orders or certificates of property use specified in the regulations. R.S.O. 1990, c. E.19, s. 176 (9); 2001, c. 17, s. 2 (45).

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Appendix C

Excerpts from Ontario Regulation 232/98 - Landfilling Sites, Environmental Protection Act

Excerpts from Ontario Regulation 232/98 - Landfilling Sites

PART I
GENERAL

DEFINITIONS

1. (1) In this Regulation,

"base side slope" means any portion of the base of the waste fill zone extending from ground surface downward at an angle steeper than one unit vertical to four units horizontal;

"buffer area" means that part of a landfilling site that is not waste fill area;

"contaminant attenuation zone" means a three-dimensional zone that,

(a) is located on land adjacent to a landfilling site,

(b) is in the subsurface or extends into the subsurface, and

(c) is used or is intended to be used for the attenuation of contaminants from the landfilling site to levels that will not have an unacceptable impact beyond the boundary of the zone;

"contaminating life span" means,

(a) in respect of a landfilling site, the period of time during which the site will produce contaminants at concentrations that could have an unacceptable impact if they were to be discharged from the site, and

(b) in respect of a landfilling site and a contaminant or group of contaminants, the period of time during which the site will produce the contaminant or a contaminant in the group at concentrations that could have an unacceptable impact if they were to be discharged from the site;

"engineered facility" means anything affixed to or made part of land that is intended to be a functional element or feature of a landfilling site for more than five years and that is created or put in place by human activity;

"maximum waste loading" means, for a landfilling site, the total waste disposal volume divided by the area of the waste fill area;

"primary leachate collection system" means the uppermost leachate collection system below the waste fill zone;

"primary liner" means the uppermost liner below the waste fill zone;

"secondary leachate collection system" means a leachate collection system located below the primary leachate collection system;

"secondary liner" means a liner located below the primary liner;

"service life" means the period of time during which a properly maintained engineered facility will function in accordance with the performance specifications for its design;

"total waste disposal volume" means, for a landfilling site, the maximum volume of waste, including the volume of any daily or intermediate cover, to be deposited at the site in the space extending from the base of the waste fill zone or the top of any engineered facilities located on the base of the site to the bottom of the final cover;

"unacceptable impact" means interference with existing or potential reasonable uses of,

(a) land,

(b) ground water in or under land, or

(c) surface water on land;

"waste fill area" means the area on the surface of a landfilling site beneath which or above which waste is disposed of by landfilling;

"waste fill zone" means the three-dimensional zone in which waste is disposed of by landfilling.

(2) The definitions in section 1 of Regulation 347 of the Revised Regulations of Ontario, 1990 also apply to this Regulation.

(3) For the purpose of better understanding the definition of "engineered facility" in subsection (1), the following things are examples of common engineered facilities, if they are intended to be functional elements or features of a landfilling site for more than five years:

1. Berms.
2. Drainage ditches.
3. Liners.
4. Covers.
5. Pumps.
6. Facilities to detect, monitor, control, collect, redirect or treat leachate, surface water or ground water.
7. Facilities to detect, monitor, control, collect, redirect, treat, utilize or vent landfill gas. O. Reg. 232/98, s. 1.

APPLICATION

2. (1) This Regulation applies to the following landfilling sites:

1. Every landfilling site that comes into existence on or after August 1, 1998 and that is intended at the time it comes into existence to have a total waste disposal volume of more than 40,000 cubic metres and to accept only municipal waste for disposal.

2. Every landfilling site for which an alteration, enlargement or extension is proposed on or after August 1, 1998 that involves an increase in the site's total waste disposal volume, if the site is intended after the alteration, enlargement or extension to have a total waste disposal volume of more than 40,000 cubic metres and to accept only municipal waste for disposal.

(2) Subsection (1) does not apply with respect to a landfilling site in respect of which an application for a certificate of approval has been received by the Director under Part V of the Act before August 1, 1998, unless the operator or owner of the landfilling site gives written notice to the Director that the operator or owner wants this Regulation to apply.

(3) The notice under subsection (2) must be given before the earlier of the following dates:

1. The date the certificate of approval or provisional certificate of approval is issued.

2. January 1, 1999.

(4) The standards, procedures and requirements set out in this Regulation do not apply to the extent that terms and conditions set out in a certificate of approval or a provisional certificate of approval issued under section 39 of the Act impose different standards, procedures or requirements. O. Reg. 232/98, s. 2.

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PART IV
FINANCIAL ASSURANCE

CONTINGENCY PLANS

17. (1) The owner and the operator of a landfilling site shall ensure that financial assurance is provided for the contingency plans for the site, including the construction, operation, maintenance and replacement of works required by the contingency plans.

(2) The financial assurance shall be provided in the form of a cash deposit paid to the Director or in such other form, such as a bond, a letter of credit or negotiable securities, as is acceptable to the Director.

(3) Subject to subsection (4), the amount of the financial assurance shall be determined in accordance with the following formula:

$$F = \$0.50 \times W \times (I_2 \div I_1)$$

where,

F = the amount of the financial assurance,

W = the number of tonnes of waste that have been deposited in the landfilling site at the time the amount of financial assurance is calculated,

I_1 = the 1997 Annual Average Non-Residential Building Construction Price Index for Toronto, determined with reference to the same base year as is applicable to I_2, as published by Statistics Canada under the authority of the *Statistics Act* (Canada),

I_2 = the most recent Annual Average Non-Residential Building Construction Price Index for Toronto available at the time the amount of the financial assurance is calculated, as published by Statistics Canada under the authority of the *Statistics Act* (Canada).

(4) The amount of financial assurance provided shall be updated annually or as otherwise required by the Director.

(5) The financial assurance shall remain in place until a written report is prepared that shows that the financial assurance is no longer required.

(6) The financial assurance may be used by the Director to pay for expenses related to any planned or unplanned closure of the site or to the post-closure care of the site, if the owner fails, on the request of the Director, to perform the work or cover the expenses.

(7) The owner and the operator of a landfilling site shall ensure that any amount of financial assurance used by the Director under subsection (6) is replaced within six months after it is used unless the Director directs otherwise.

(8) Subsection (1) does not apply to require site specific financial assurance if financial assurance for the contingency plans is provided by a group financial assurance plan acceptable to the Director.

(9) Subsection (1) does not apply in respect of a landfilling site owned by a municipality or the Crown.

(10) Subsection (1) does not apply to a landfilling site owned by a forest products company if the waste to be deposited at the site is produced by forest products operations, such as the operations of a lumber mill, sawmill, pulp mill or similar facility, and is predominantly solid, non-hazardous process waste, such as woodwaste, effluent treatment solids, hog fired boiler ash, recycling process rejects, lime mud, grits or dregs. O. Reg. 232/98, s. 17.

CLOSURE AND POST-CLOSURE CARE

18. (1) The owner and the operator of a landfilling site shall ensure that financial assurance for the closure of the site and the post-closure care of the site is provided in accordance with this section.

(2) The financial assurance shall be provided in the form of a cash deposit paid to the Director or in such other form, such as a bond, a letter of credit or negotiable securities, as is acceptable to the Director.

(3) The amount of the financial assurance shall be the present value at the estimated date of closure, in dollars current at that date, of an amount sufficient to cover the estimated costs for,

(a) the planned closure of the largest area that will require final cover at any one time during the operation of the site, including the costs of final cover and landscaping;

(b) care and maintenance of the final cover and landscaping for the contaminating life span of the site; and

(c) all other expected post-closure care activities for the contaminating life span of the site, including monitoring, analysis and reporting, the design, construction, operation, maintenance and replacement of engineered facilities and the disposal of wastes from the facilities, but not including any additional activities in the contingency plans for the site.

(4) Any determination of the amount of the financial assurance shall be carried out in a manner consistent with Ministry of Environment and Energy Guideline F - 15, Financial Assurance, dated April 1994, and Ministry of Environment and Energy Procedure F - 15 - 1, Procedures for Financial Assurance, dated April 1994, as they may be amended from time to time.

(5) Clause (3) (a) does not apply if part of the site is closed not less often than every five years.

(6) If costs are estimated under subsection (3) for any matter related to leachate from the site, the contaminating life span of the site may not be estimated at less than 25 years from the date waste is last deposited at the site.

(7) The financial assurance may be provided in stages as long as the amount that has been provided is always greater than the minimum amount determined in accordance with the following formula:

$$A = B\,(C \div D)$$

where,

A = the minimum amount of financial assurance that must have been provided,

B = the total amount of the financial assurance, as estimated under subsection (3),

C = the amount of waste that has already been deposited at the site,

D = the total amount of waste that will be deposited at the site.

(8) The estimation of costs and the amount of the financial assurance provided shall be updated annually or as otherwise required by the Director.

(9) The financial assurance shall remain in place until a written report is prepared that shows that the financial assurance is no longer required.

(10) The financial assurance may be used by the Director to pay for expenses related to any planned or unplanned closure of the site if the owner fails, on the request of the Director, to perform the work or cover the expenses.

(11) The owner and the operator of a landfilling site shall ensure that any amount of the financial assurance used by the Director under subsection (10) is replaced within six months after it is used unless the Director directs otherwise.

(12) Subsection (1) does not apply in respect of a landfilling site owned by a municipality or the Crown. O. Reg. 232/98, s. 18.

* * * * *

Appendix D

Excerpts from Regulation 352 - Mobile PCB Destruction Facilities, Environmental Protection Act

Excerpts from Regulation 352 - Mobile PCB Destruction Facilities

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1. In this Regulation,

"local municipality" means a city, town, village, township or improvement district;

"mobile PCB destruction facility" means movable, transportable machinery or equipment that is intended to destroy the chemical structure of PCBs;

"PCB" means any monochlorinated or polychlorinated biphenyl or any mixture of them or mixture that contains one or more of them;

"PCB equipment" means equipment designed or manufactured to operate with PCB liquid or to which PCB liquid was added or drums and other containers used for the storage of PCB liquid;

"PCB liquid" means liquid containing PCBs at a concentration of more than fifty milligrams per kilogram;

"PCB material" means material containing PCBs at a concentration of more than fifty milligrams per kilogram whether the material is liquid or not;

"PCB waste" means,

(a) PCB equipment,

(b) PCB liquid, or

(c) PCB material,

but does not include,

(d) PCB material or PCB equipment after it has been decontaminated pursuant to guidelines or codes of practice published by the Ministry of the Environment,

(e) PCB equipment that is,

(i) an electrical capacitor that has never contained over one kilogram of PCBs,

(ii) electrical, heat transfer or hydraulic equipment or a vapour diffusion pump that is being put to the use for which it was originally designed or is being stored for such use by a person who uses the equipment for the purpose for which it was originally designed, or

(iii) machinery or equipment referred to in subclause (f) (i), or

(f) PCB liquid that is,

(i) at the site of fixed machinery or equipment, the operation of which is intended to destroy the chemical structure of PCBs by using the PCBs as a source of fuel or chlorine for a purpose other than the destruction of PCBs or other wastes and with respect to which a certificate of approval has been issued under section 9 of the Act specifying the manner in which PCB liquid be processed in the machinery or equipment, or

(ii) in PCB equipment referred to in subclause (e) (ii). R.R.O. 1990, Reg. 352, s. 1.

*   *   *   *   *

8. (1) Every applicant, other than a municipality, for a certificate of approval for a Class 1 mobile PCB destruction facility waste disposal site shall,

(a) deposit a sum of money;

(b) furnish a surety bond; or

(c) furnish personal sureties,

in the amount of $50,000.

(2) Every applicant, other than a municipality, for a certificate of approval for a Class 2 mobile PCB destruction facility waste management system shall,

(a) deposit a sum of money;

(b) furnish a surety bond; or

(c) furnish personal sureties,

in the amount of $50,000 for each mobile PCB destruction facility operating in Ontario.

(3) Where the applicant, during operation of the site or within sixty days after giving the Director notice that the equipment is disassembled and the site is terminated, fails to comply with the Director's requirements to remove such waste or to carry out such actions as the Director considers necessary to ensure satisfactory maintenance of the equipment or the site, the money, bond or sureties deposited or their proceeds may be used by the Director in carrying out the necessary actions. R.R.O. 1990, Reg. 352, s. 8.

*   *   *   *   *

Appendix E

Templates for Standard Non-Cash Forms of Financial Assurance

Templates for Standard Non-Cash Forms of Financial Assurance

The following templates can be revised to fit specific circumstances. However, if forms provided by issuing institutions (for example, banks, surety companies) are presented by approval applicants or recipients of orders, these forms should be reviewed by Legal Services Branch and other appropriate Ministry staff to ensure that provisions of Part XII of the *Environmental Protection Act*, the terms and conditions of the order or approval and the intent of the guideline are preserved and implemented.

The blanks and **bold** words do not belong in the Financial Assurance form. The square brackets do not belong in the Financial Assurance form. Ensure that they are deleted from the final, completed version of the document. For example, this means that if a Ministry official has not provided the titles of one or more positions the words in square brackets and the square brackets “[other appropriate MOE official's title supplied by MOE]” must be deleted.

The optional addition (*) can be varied to meet the circumstances. For example, the bond should refer to the order or approval and to the waste management system, landfill, sewage works, source of air emissions or any other facility or pollution source that is the subject of the order or approval.

If a standard or non-standard, non-cash Financial Assurance form is to be accepted instead of cash, the order or approval requiring the provision of the Financial Assurance should specify that, in the event of a notice of expiry, non renewal or other termination of the security is received or another event happens which impairs the Financial Assurance, the standard or non-standard Financial Assurance should be immediately replaced by cash. Some standard or non-standard types of Financial Assurance such as some surety bonds and insurance policies may not be convertible to cash. Special terms and conditions will be required in the order or approval which will enable the Director to start the closing down and clean-up of the operation in the event the Financial Assurance is being terminated and start a claim against the issuer of the Financial Assurance before it terminates.

The surety bond template shown is an example of a surety bond for a waste disposal certificate of approval. With suitable changes, this template can be adapted for other environmental activities and requirements.

If any changes are made to these templates, the issuing bank or other institution must obtain Ministry approval of these changes before it is accepted as Financial Assurance. The regulated party (the bank’s customer) is normally responsible for obtaining Ministry approval for the issuing institution. Delays can be avoided if a draft of the proposed form is reviewed at an earlier date.

Some operators present letters of credit of a foreign bank guaranteed by an Ontario bank. Frequently the form of documentation is confused and needs careful advance scrutiny.

<u>Example/Template for a Surety Bond</u>
(Typed on the letterhead of the issuing institution)

To: Her Majesty the Queen in Right of Ontario
as Represented by the Minister of the Environment (the "Crown")

APPROVAL/ORDER NUMBER: _____________________ AMOUNT: $ _______________
SITE LOCATION: ____

Know all men by these presents that we, ____________________________ (the "Principal") and ____________________________ (the "Surety")

are jointly and severally bound to Her Majesty the Queen in Right of Ontario as Represented by the Minister of the Environment (the "Crown"), in the sum of **[spell out amount in words and check to ensure the words and figures match]** dollars, lawful money of Canada, for the payment of which sum, well and truly to be made, the Principal and Surety bind themselves, their heirs, executors, administrators, successors and assigns, jointly and severally, by this bond;

WHEREAS the Principal is desirous of obtaining **[insert Certificate of Approval/Provisional Certificate of Approval or appropriate order reference]** from the Ministry of the Environment to operate **[something]** at **[insert location of disposal site*]**; **[modify those phrases to suit]**

WHEREAS the Principal must furnish a Financial Assurance to the Crown pursuant to Part XII of the *Environmental Protection Act* with respect to the **[insert describe waste disposal sites*]**;

WHEREAS the Principal and Surety acknowledge that they have read the Financial Assurance Guideline dated November 2005 and Part XII of the *Environmental Protection Act*, both of which relate to this bond.

The aforesaid sum shall be paid to the Ontario Minister of Finance forthwith on written demand upon the Surety, to be held for purposes of Part XII of the *Environmental Protection Act*. The demand made by the Crown shall be honoured by the Surety without enquiring whether the Crown has a right as between Crown and the Principal to make such demands, and without recognizing any claim of the Principal and the Principal and the Surety each consent to the Crown obtaining, on written notice, summary judgements for the full amount secured hereunder if payment is not made forthwith upon demand.

The condition of the above obligation is that if the Principal **[and the Operator and their heirs, successors and assigns]** shall well and truly, in all respects duly fulfil execute and observe all terms and conditions and requirements of the **[insert *Environmental Protection Act* and (where relevant) the *Ontario Water Resources Act*]** then this obligation shall be void and of no effect but otherwise shall be and remain in full force, virtue and effect.

Nevertheless if the Surety at any time gives 60 days notice in writing to the Principal **[the Operator]** and to the Crown of the Surety's intention to put an end to the Suretyship hereby entered into, then this bond and all accruing responsibility thereunder shall from and after the last day of such 60 days aforesaid cease and determine except insofar as the Principal has made default prior to the said last day of such period.

Nevertheless, the obligations of the Principal or the Surety for this bond or renewal will be limited to the amount stated above or the amount stated on the renewal Certificate of Approval issued by the Ministry of the Environment provided that the amount stated on a renewal Certificate of Approval shall not be less than the amount stated above or on the most recent renewal Certificate of Approval unless the Director under the **[insert *Environmental Protection Act* and (where relevant) the *Ontario Water Resources Act*]** has consented in writing to a lower amount.

This bond will be valid for the term from **[insert day]** day of **[insert month]**, [insert year] to [insert day] day of **[insert month]**, **[insert year]** and shall be automatically renewed without further documentation from year to year thereafter on the same terms and conditions (including this one for renewal) unless at least 60 days' written notice, as provided for above, is given that it will not be so renewed and the Crown may call for payment on the full amount prior to the date of termination provided that the Surety may, if it wishes, issue Certificates of Approval evidencing such renewal.

Any notice hereunder may be given,

(a) in the case of the Crown by registered mail or prepaid courier to:
The Director
Environmental Assessment and Approvals Branch
Ministry of the Environment
2 St. Clair Avenue West, Floor 12A
Toronto, Ontario M4V 1L5

[and if an order, a copy to:
Regional Director
_______________ Region
Ministry of the Environment
appropriate Regional and District Office Addresses]

(b) in the case of the Principal by prepaid mail to:
[insert Principal's Name]
[insert Principal's Address]

(c) in the case of the Surety by delivery to or by prepaid mail to:
[insert Surety's Name]
[insert Surety's Address (must be located in Ontario and the Surety must be licenced by Ontario to issue such bonds in Ontario)]

[(d) add paragraphs for Operator or other parties, if necessary]

or such other address as the recipient has, from time to time, given the sender, written notice, provided such written notice specifies it is given with respect to **[insert waste disposal site*]** and this bond and the Surety may not give notice specifying an address outside of the Province of Ontario without the written consent of the Crown.

Any notice by the Crown may be signed by the Director of the **[insert Environmental Assessment and Approvals Branch or appropriate Regional Office as applicable]** of the Ministry of the Environment, the Assistant Deputy Minister of the Corporate Management Division or of the Operations Division of the Ministry of the Environment, the Deputy Minister of the Environment or such other person as the Deputy Minister of the Environment or Minister of the Environment appoints in writing for the purpose.

The Surety acknowledges that it is aware that if notice terminating this bond is issued prior to the Crown receiving substitute Financial Assurance satisfactory to the responsible Director, the Crown is entitled to convert this bond into cash to be held in the Consolidated Revenue Fund as Financial Assurance and that the Crown may obtain a lien against affected property in priority to other liens and charges in the event of a default with respect to such property under the *Environmental Protection Act* or the *Ontario Water Resources Act* by the Principal **[and the Operator or their]** or its successors.

IN WITNESS WHEREOF this bond has been duly signed, sealed and delivered

Legal Name of Surety

per: ____________________ c/s

Legal name(s) of Principal

per: ____________________

(Use appropriate style of signature depending on whether individual, sole proprietor, partnership or corporation names should be typed and office of person signing on behalf of a corporation or other firm should be set out.)

<u>Example/Template for an Irrevocable Letter of Credit</u>
(Typed on the letterhead of the bank)

To: Her Majesty the Queen in Right of Ontario
as Represented by the Minister of the Environment (the "Crown")

APPROVAL/ORDER NUMBER: ____________________ AMOUNT: $ _______________

SITE LOCATION: ____

We hereby authorize the Crown to draw on the **[insert Name of Bank] [must be an Ontario Branch]** for account of **[insert Company's name]**, **[insert Company's Address]**, Ontario, an aggregate amount of **[insert amount in words]** dollars ($**[insert amount in figures]**) of lawful money of Canada available by demand.

Pursuant to the request of our customer, **[insert Company's name]**, we hereby establish and give to the Crown an Irrevocable Letter of Credit in the Crown's favour which may be drawn on by the Crown at any time and from time to time upon written demand for payment made upon us by the Crown, which demand we shall honour without enquiring whether the Crown has a right as between the Crown and our said customer to make such demands, and without recognizing any claim of our said customer. This Irrevocable Letter of Credit will continue up to **[insert day]** day of **[insert month]**, **[insert year]**, and will be automatically renewed for one year on the same terms and conditions (including this one for renewal) unless we give the Crown at least 60 days' written notice that it will not be so renewed and the Crown may call for payment on the full amount outstanding under this Irrevocable Letter of Credit at any time prior to that date should this Irrevocable Letter of Credit not be renewed.

We acknowledge having read the Financial Assurance Guideline dated November 2005 and issued by you, the Crown, and Part XII of the *Environmental Protection Act*.

Partial drawings are permitted. Any payments made hereunder shall be in favour of the Ontario Minister of Finance.

The amount secured by this Irrevocable Letter of Credit may be reduced from time to time by written notice to the Bank from you, the Crown.

Any notice under the previous paragraph or any demand hereunder may be made by the Director of the **[insert Environmental Assessment and Approvals Branch or appropriate Regional Office as applicable]** of the Ministry of the Environment, the Assistant Deputy Minister of the Corporate Management Division or of the Operations Division of the Ministry of the Environment, the Deputy Minister of the Environment or such other person as the Deputy Minister of the Environment or Minister of the Environment appoints in writing for the purpose.

Any notice hereunder may be given,

in the case of the Crown by registered mail or prepaid courier to:

The Director
Environmental Assessment and Approvals Branch
Ministry of the Environment
2 St. Clair Avenue West, Floor 12A
Toronto, Ontario M4V 1L5

[and if an order, a copy to:

Regional Director
_______________ Region
Ministry of the Environment
appropriate Regional and District Office Addresses]

The Crown's claim under this Irrevocable Letter of Credit must be in writing addressed to the **[insert name and address of issuing Bank]**, Ontario quoting our Irrevocable Letter of Credit Number **[insert letter of credit number]** dated **[insert month and day], [insert year]**.

We hereby agree with the Crown that demands made in compliance with the terms of this credit shall be duly honoured upon presentation at the Bank.

____
Authorized Signing Officers

Appendix F

Flow Charts Showing Financial Assurance Procedures and Responsibilities

Chart F1: Categories of Financial Assurance, According to Degree of Staff Discretion

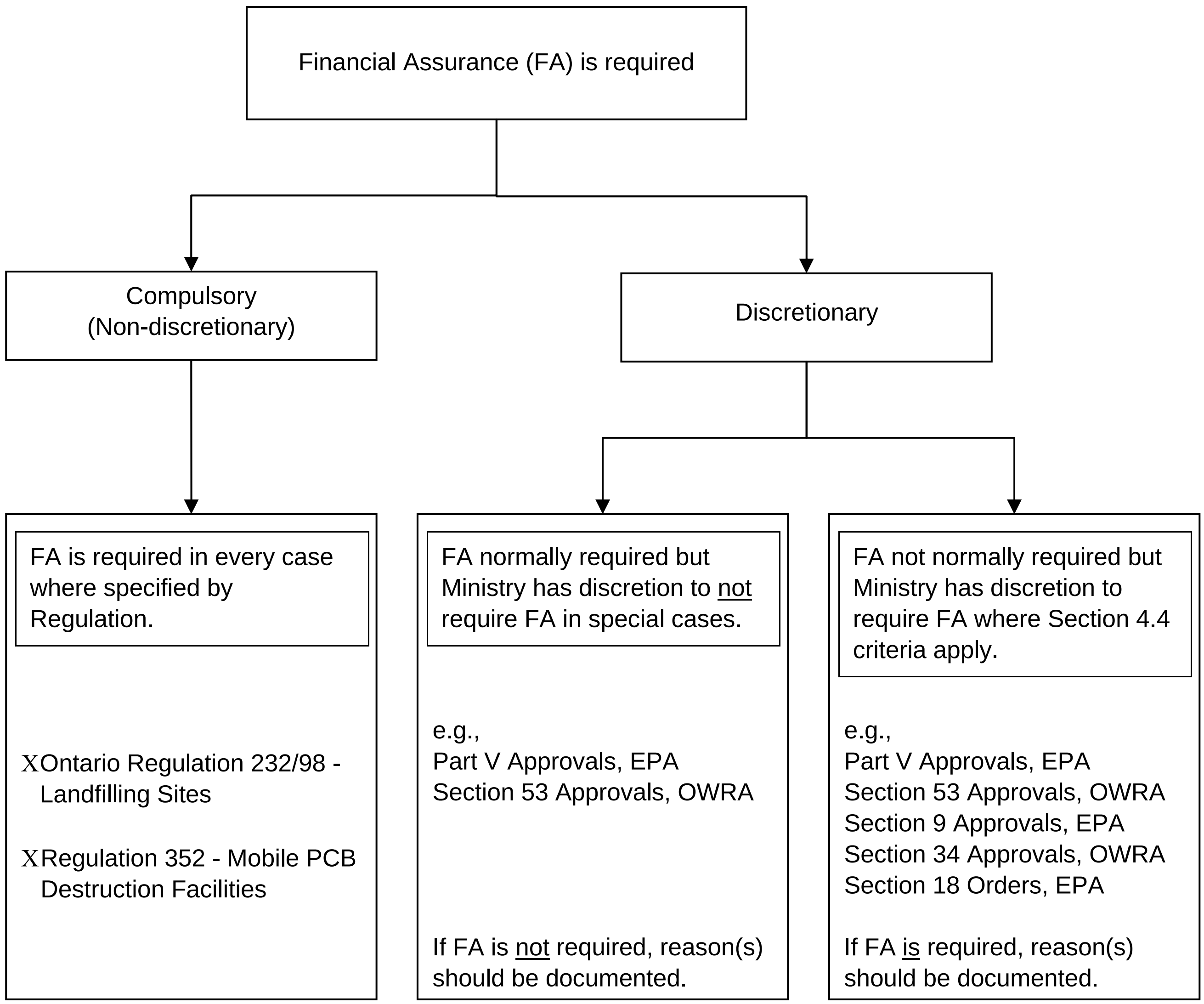
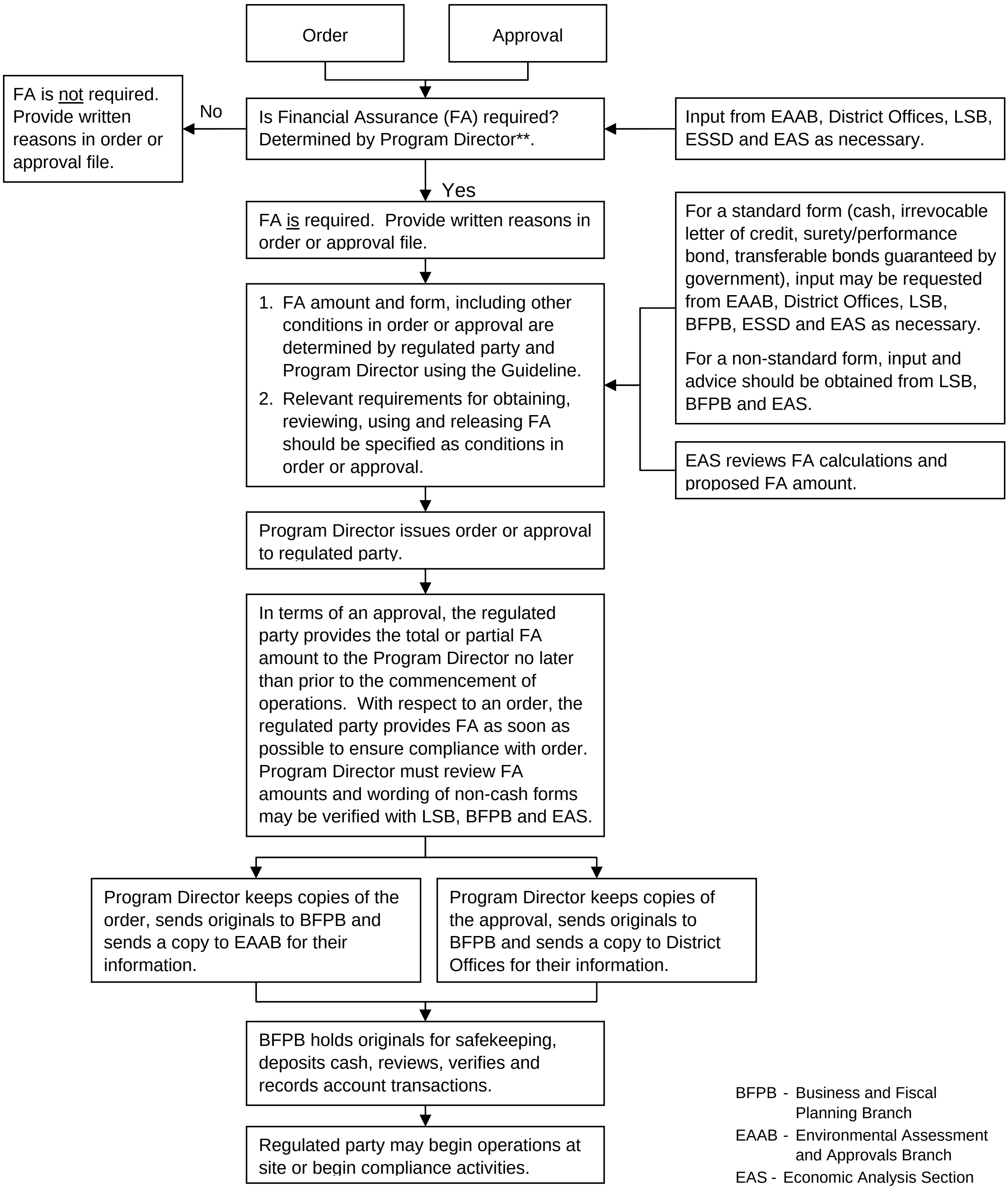


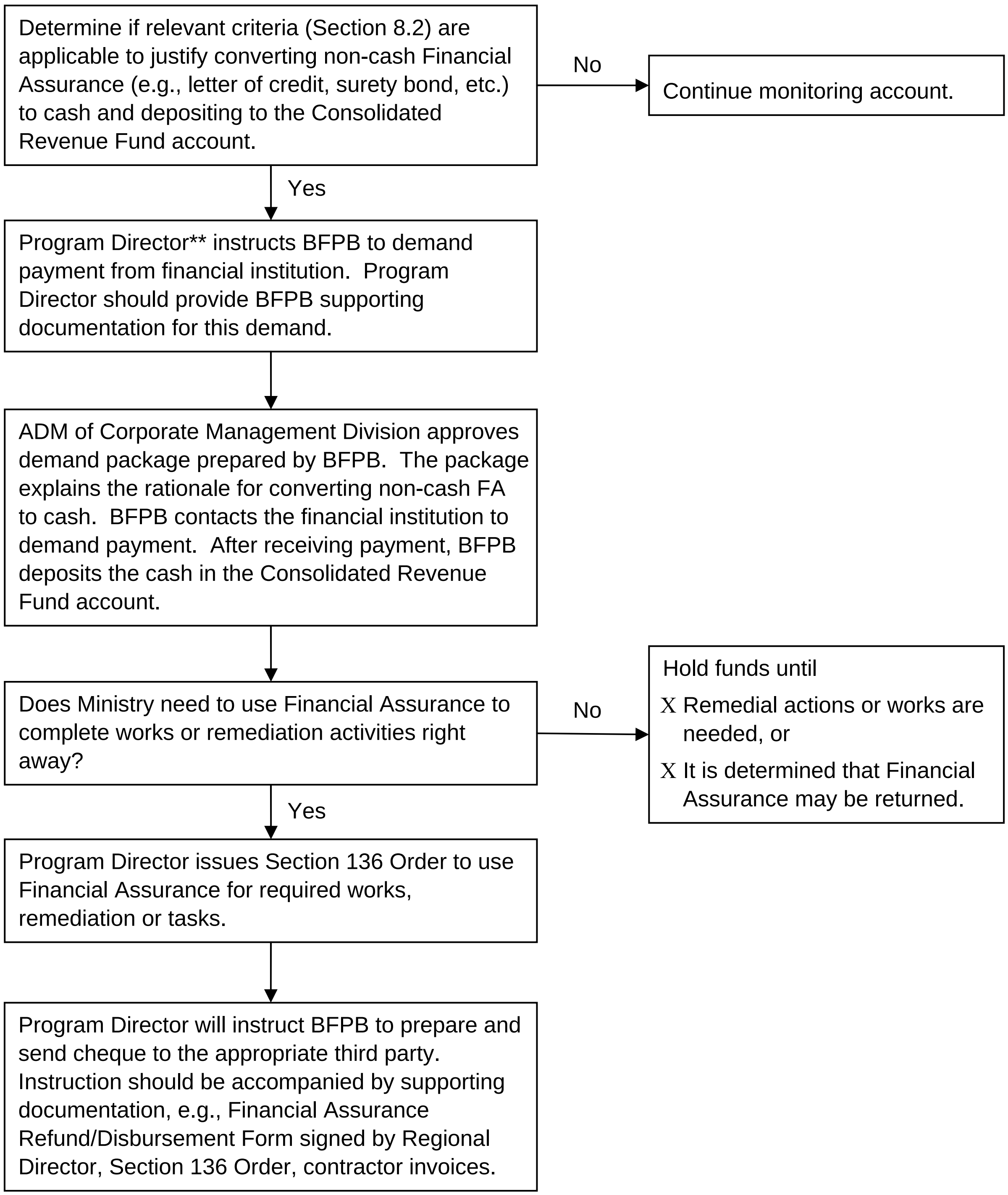
Chart F2: Procedures for Obtaining Financial Assurance and Handling Documents



BFPB - Business and Fiscal Planning Branch
EAAB - Environmental Assessment and Approvals Branch
EAS - Economic Analysis Section
ESSD - Environmental Sciences and Standards Division
LSB - Legal Services Branch

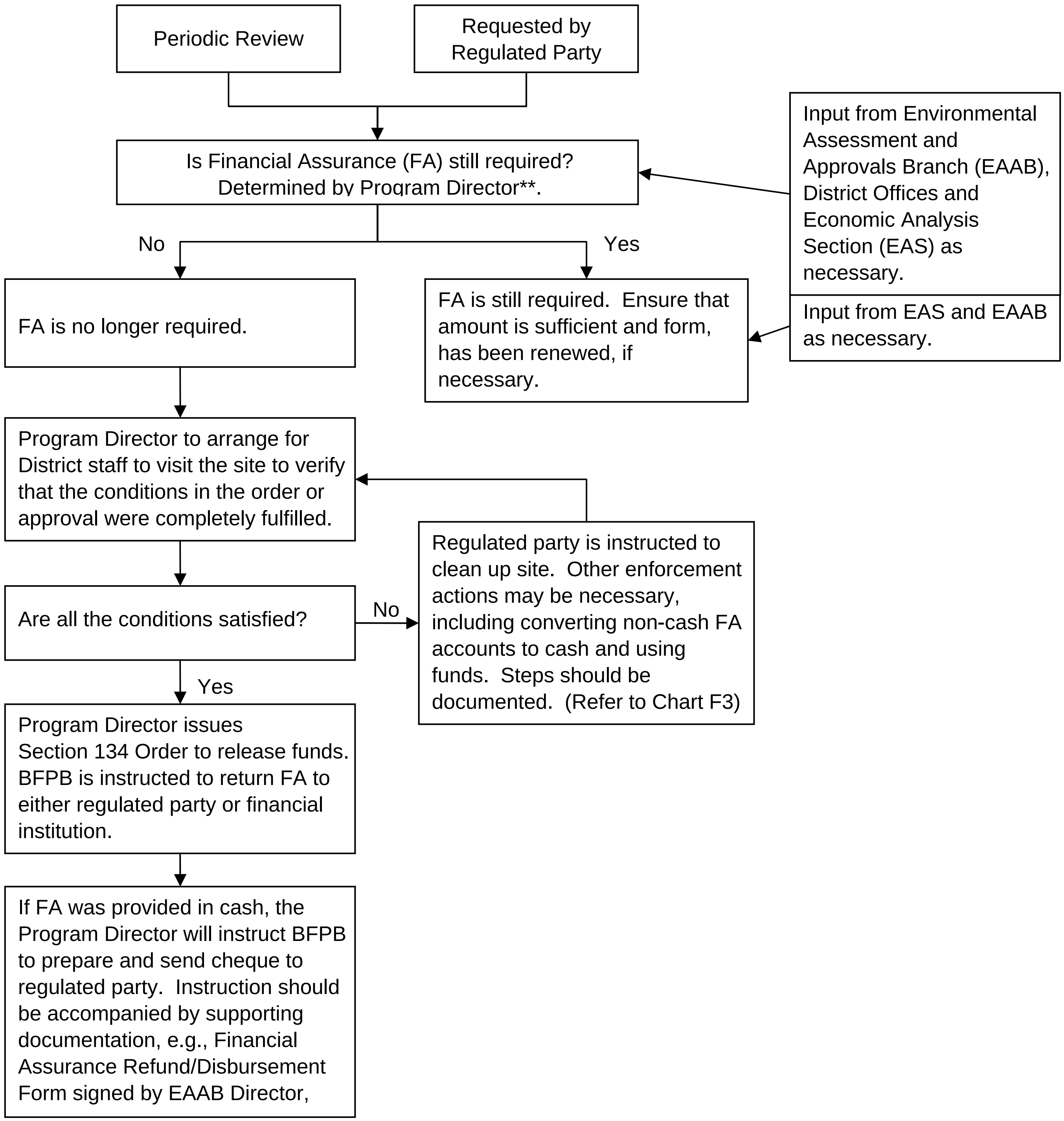
** Program Director as defined in Appendix J of Guideline

Chart F3: Converting Non-Cash Financial Assurance to Cash and Using Financial Assurance



** Program Director as defined in Appendix J of Guideline

Chart F4: Procedures for Returning Financial Assurance



** Program Director as defined in Appendix J of Guideline

Appendix G

List of Planned Landfill Closures and Post-Closure Care Activities

TABLE G: List of Planned Landfill Closures and Post-Closure Care Activities

PLANNED LANDFILL CLOSURES AND POST-CLOSURE CARE ACTIVITIES
LANDFILL AREA **AREA TO BE CLOSED (REQUIRES FINANCIAL ASSURANCE)**
Planned Closure Items
Capping of old landfill
Clay for cover
Sign replacement
Clean-up: litter, debris on and around site
Fuel tank removal
Removal of structures
Repair of leachate seeps
Final cap application
Topsoil application
Seeding finished areas
Topsoil and seeding
Drainage ditch construction
Tree and shrub planting
Installation of observation wells
Closure plan
Repair access road
Removal of sediment pond
Post-Closure Care Items
Cap and topsoil repairs
Cap repair
Erosion repair
Grass cutting
Ditch maintenance
Leachate collector flushing
Semi annual inspections and routine maintenance
Annual monitoring
Site inspections
Annual water monitoring, laboratory analyses, report preparation
Site surface maintenance
Repair of defective monitoring wells
Road granular (one-time cost in yr. XXIX)
Access road repair and snow removal
Taxes

Appendix H

Spreadsheet Template for Calculating Financial Assurance Amounts for a Typical Landfill Site, According to Ontario Regulation 232/98

Spreadsheet Template for Calculating Financial Assurance Amounts for a Typical Landfill Site after 1998 (according to Ontario Regulation 232/98)

Introduction

An Excel spreadsheet example is presented in this Appendix to show, in detail, how to determine Financial Assurance for a typical private sector landfill operation according to Ontario Regulation 232/98. The spreadsheet template, which may be obtained from the Environmental Assessment and Approvals Branch of the Ministry of the Environment or the Economic Analysis Section in the Ministry of Energy, contains the formulas and algorithms defined below and can be used with little modification to calculate the amounts of Financial Assurance for closure, post-closure care and maintenance and contingency costs for a particular site.

Financial Assurance for a landfill site is intended to secure funds for:

- Closure of the site when the landfill capacity is exhausted.
- Post-closure care costs such as monitoring, analysis and reporting, design, construction, operation, maintenance and replacement of engineered facilities, etc.
- Unexpected contingency costs such as construction, operation, maintenance and replacement of works to collect and process gas or leachate and to repair liner failure or to compensate offsite properties. Compensation is limited to situations where there is statutory authority.

As explained in the Guideline, the amount of Financial Assurance to be provided must be sufficient to pay the total capital and operating costs of specified closure activities plus the costs of post-closure care over the contaminating life span of the landfill. In addition, there should be a separate Financial Assurance fund to pay for unexpected contingencies.

Table H1: Closure and Post-Closure Care Activities, Costs, Landfill Specifications and Financial Inputs

In this example, illustrative closure and post-closure care activities are listed in Table H1 along with the estimated one-time capital or annual operating costs (in 2004 dollars) for each activity. Expenditure patterns for different activities can change over time. For example, cost item 1PC in Table H1 increases from $500 to $1,500 and then decreases to $1,250 over the planning period for the landfill because the amount of work needed varies at different stages in the life of the landfill site. Other relevant variables needed for these calculations (i.e., closure, site capacity, annual amount of solid wastes disposed of each year, inflation and discount rates, etc.) are also presented. Closure and post-closure care activities shown in Table H1 can vary based on the characteristics of the landfill.

Estimates of the capital and operating costs for each closure and post-closure item must be provided by landfill owners or operators who are recipients of orders, approvals and/or who are required to comply with Ontario Regulation 232/98 - Landfilling Sites. Ministry of the Environment officials should review and verify these estimates to the extent possible. Verification may be accomplished by site visits, calling vendors, reviewing other approval files for landfills and by reviewing the literature in trade magazines. If cost estimates are not submitted, the approval application and Financial Assurance proposal will not be reviewed and will be returned to the regulated party.

Table H1: Closure and Post-Closure Care Activities, Costs, Landfill Specifications and Financial Inputs

Relevant Information Required:	**Illustrative Data**
Landfill Specifications	
First Year of Operations:	January 2004
Year of Closure:	January 2024
Planning Period:	60 Years (January 2004 - December 2063)
Contaminating Life Span:	40 Years (January 2024 - December 2063)
Site Capacity:	60,000 tonnes
Annual Fill Rate:	3,000 tonnes/year
Form of Financial Assurance:	Letter of Credit
Financial Inputs	
2003 Annual Average Non-Residential Building Construction Price Index for Toronto:	123.8
1997 Annual Average Non-Residential Building Construction Price Index for Toronto:	100.0
Interest (Discount) rate (Selected Government of Canada Benchmark Bond Yields: Long-Term, January 31, 2004	5.23%
Percentage Change between the most recent (Year 2003) Annual Average Non-Residential Building Construction Price Index and the 1997 Index:	3.4%

Cost Information (2004 dollars)

Closure Costs Project

	Activity	**One-time Payment**	**Annual Payment**
1CC	Clean up of litter and debris	$500	
2CC	Repair of leachate seeps	$500	
3CC	Final cover application	$8,750	
4CC	Topsoil application	$2,500	
5CC	Seeding finished areas		$1,500
6CC	Drainage ditch construction	$600	
7CC	Tree and shrub planting	$5,000	
8CC	Site inspections and routine maintenance		$5,000
9CC	Water monitoring, lab analyses, report preparation		$3,250
10CC	Installation of leachate collection/treatment system	$62,500	
11CC	Installation of methane gas collection/treatment system	$50,000	
12CC	Operation of leachate collection system		$25,000
13CC	Operation of methane gas collection system		$12,500
1PC	Repair of defective monitoring wells (from 2024 to 2043)		$500
1PC	Repair of defective monitoring wells (from 2044 to 2052)		$1,500
1PC	Repair of defective monitoring wells (from 2054 to 2063)		$1,250
2PC	Replace/repair of monitoring wells (year 2024 and 2043)	$7,500	
3PC	Replacement of fencing (year 2027 and 2052)		$12,500

CC = Closure Costs
PC = Post-Closure Care Costs

Estimated costs are presented as an example. Unit costs should be obtained for the site in question and should be incorporated in Table H1. These costs should then be used in Table H2.

Table H2: Financial Assurance Calculation for Landfill Site

Financial Assurance for Closure and Post-Closure Care Costs

Calculating Financial Assurance for closure and post-closure care costs involves a four-step approach:

- Step 1: Derive annual inflation rate using the Annual Average Non-Residential Building Construction Price Index for Toronto (NRCPIT);
- Step 2: Inflate costs (using the rate derived in Step 1) to arrive at the total future costs expected to be incurred at and after closure;
- Step 3: Discount total future costs back to the year of closure to determine how much Financial Assurance, net of interest, is required from the regulated party; and
- Step 4: Submit the calculated Financial Assurance amount from Step 3 above according to the accumulated amount of waste deposited each year during the operating period of the landfill.

Using the cost estimates provided in Table H1, Table H2 presents forecasts of closure and post-closure cost items to be incurred each year, starting from the year in which the site is intended to close (2024 in this example). The expected closure year is defined as "year one" of the contaminating life span and "year zero" for discounting purposes. In this example, a 40-year contaminating life span is assumed.

Inflation and discount rates used in this example are 3.4 per cent and 5.23 per cent respectively and represent rates as of February 2004. Sources of inflation and discount rates to be used are defined in the Guideline. Clear references to the actual rates used must be provided in regulated parties' Financial Assurance proposal. When needed annual fill rates are to be provided by the proponent. At regular intervals, the Financial Assurance estimates are to be updated by new price indices and fill rates.

Step 1:

The NRCPIT, published by Statistics Canada, Catalogue 62-007, is used in the following formula to derive the annual inflation rate. Using the most recent (2003) NRCPIT, the inflation rate is calculated to be 3.4%:

Inflation rate = [(Year 2003 NRCPIT - Year 1997 NRCPIT) ÷ Year 1997 NRCPIT] ÷ (number of years in between the two indices + 1) × 100%

$$= [(123.8 - 100) \div 100] \div (6 + 1) \times 100\%$$

$$= 3.4\%$$

Step 2:

Once the inflation rate is derived, it is used/applied in the following formula to calculate the value of the total future costs by inflating costs each year from 2004 to year 2024.

$F(n+1) = \quad C(n) \times (1+i)^n$

where,

n = year 0, 1, 2, 3, ..., N

year 0 = base year = year when project is initiated

N = final year of planning period

F(n+1) = future capital and operating costs in year n+1

C(n) = annual capital and operating costs expended in year n; initial capital and operating costs expended in year n = 0

i = inflation rate derived from NRCPIT

From Table H2, costs are summed across rows to show the total annual expenditures expressed in current dollars. The total future value which is equal to $7,938,588 noted in Column U, "Undiscounted Future Expenditures $'s".

Step 3:

The discount rate to be used is the most recent monthly rate for Government of Canada Benchmark Bond Yields: Long-Term, as published in the Bank of Canada website. The most recent discount rate as of January 31, 2004 is 5.23%. This rate is used to calculate present values.

Present values are calculated using the "@PV" function of the Quattro Pro or Excel spreadsheet software or the following formula found in Section 6.7.6.5 in the Guideline:

$\text{PV Cost}(n+1) = \quad \sum(\text{sum of}) [F(n) \div (1+r)^n]$

where,

n = year 0, 1, 2, 3, 4, 5, ..., N

year 0 = base year: in the case of landfills, year of site closure, when discounting year N = final year of planning period (or of contaminating life span for landfills)

F(n) = future (inflated) capital and operating costs

PV Cost(n+1) = present value of future capital and operating costs in year n+1

r = discount rate

From Table H2, the total present value for the period from year 2024 to 2063 yields an estimate of $2,958,525 found in Column V, "Closure Year 2024 Expenditures $'s". At the year of closure, this is the total amount of funds that would have to be deposited in order to generate sufficient compound interest to yield an estimated future amount that would pay for the closure and post-closure care costs of $7,938,588.

Step 4:

Prior to site closure, the closure/post-closure care funds to be paid each year are proportional to the cumulative amount of waste deposited in the site each year and must sum to the total present value of $2,958,525 in year 2023, one year prior to closure. The following formula is used to arrive at the Financial Assurance payments:

$$A = B (C \div D)$$

where,

A = the minimum amount of Financial Assurance that must have been provided;

B = the total amount of Financial Assurance for closure/post-closure costs;

C = the amount of waste that has already been deposited at the site; and

D = the total amount of waste that will be deposited at the site (equal to site capacity).

Since future NRCPITs are unknown and fill rates are forecasts only, the regulated party is required, at least every three years, to update these rates and use them to recalculate the Financial Assurance amounts.

During each year within the operating period, the regulated party is required to increase their Financial Assurance amount according to the Cumulative Financial Assurance Balance for closure and post-closure noted in Column AB.

After site closure, the Financial Assurance amount will be adjusted each year to account for interest earned and maintenance expenditures incurred. The amount of Financial Assurance should be reviewed periodically to ensure the Financial Assurance in place is sufficient to pay for all the anticipated costs. Financial Assurance amounts may be increased or decreased as the result of these reviews.

Before closure, the Cumulative Financial Assurance Balance schedule for closure and post-closure is found in Column AB and after closure, it is found in Column AC in Table H2.

Financial Assurance for Contingency Costs

Calculating Financial Assurance for contingency costs consists of one step. The NRCPIT and fill rates are used in the contingency cost formula noted below to arrive at the Financial Assurance amount for each year prior to closure. After closure, the Financial Assurance amount for contingencies remains constant throughout the contaminating life span. If a portion or the entire Financial Assurance amount is used to pay for any planned or unplanned closure of the site or to the post-closure care of the site, the regulated party is required to replace the Financial Assurance amount within six months.

$$F = \$0.50 \times W \times (I_2 \div I_1)$$

where,

F = the amount of the Financial Assurance,

W = the number of tonnes of waste that have been deposited in the landfilling site at the time the amount of Financial Assurance is calculated,

I_1 = the 1997 Annual Average Non-Residential Building Construction Price Index for Toronto, determined with reference to the same base year as is applicable to I_2, as published by Statistics Canada under the authority of the *Statistics Act* (Canada),

I_2 = the most recent Annual Average Non-Residential Building Construction Price Index for Toronto available at the time the amount of the Financial Assurance is calculated, as published by Statistics Canada under the authority of the *Statistics Act* (Canada).

Total Financial Assurance amount for contingency costs from year 2004 to 2023 yields an estimate of $37,140 found in Column AD, “FA Accumulated for Contingency Costs”.

Since future NRCPITs are unknown and fill rates are forecasts only, the regulated party is required, at least every three years, to update these rates and use them to recalculate the Financial Assurance amounts.

Total Financial Assurance

The total annual Financial Assurance required by the regulated party can be found in the last column, Column AE in Table H2. The total Financial Assurance required each year is the sum of the cumulative Financial Assurance balance required for closure and post-closure care plus the cumulative balance required for the contingency fund. For example, in year 2050, the regulated party would have to provide a total Financial Assurance amount of $2,617,784 which includes $2,580,644 for the closure and post-closure fund and $37,140 for the contingency fund.

At the end of the planning period, any remaining Financial Assurance may be returned to the regulated party after the Program Director is satisfied that all conditions have been met and no future expenditures are anticipated.

Table H2:Financial Assurance Calculations for Landfill: Planned Closure and

Post-closure Care Items ($'s) - Used Interest Rate: 5.23% (1) and Inflation Rate: 3.4% (2)

Year	Number of Years For Discounting	Item 1PL (Capital)	Item 2PL (Capital)	Item 3PL (Capital)	Item 4PL (Capital)	Item 5PL (Capital)	Item 6PL (Capital)	Item 7PL (Capital)	Item 8PL (Operating)	Item 9PL (Operating)	Item 10PL (Capital)	Item 11PL (Capital)	Item 12PL (Operating)	Item 13PL (Operating)
A	**B**	**C (4) C*1.034**	**D (4) D*1.034**	**E (4) E*1.034**	**F (4) F*1.034**	**G (4) G*1.034**	**H (4) H*1.034**	**I (4) I*1.034**	**J (4) J*1.034**	**K (4) K*1.034**	**L(4) L*1.034**	**M (4) M*1.034**	**N (4) N*1.034**	**O (4) O*1.034**
2004 (Row 7)		$ 500	$ 500	$ 8,750	$ 2,500	$ 1,500	$ 600	$ 5,000	$ 5,000	$ 3,250	$ 62,500	$ 50,000	$ 25,000	$ 12,500
2005		$ 517	$ 517	$ 9,048	$ 2,585	$ 1,551	$ 620	$ 5,170	$ 5,170	$ 3,361	$ 64,625	$ 51,700	$ 25,850	$ 12,925
2006		$ 535	$ 535	$ 9,355	$ 2,673	$ 1,604	$ 641	$ 5,346	$ 5,346	$ 3,475	$ 66,822	$ 53,458	$ 26,729	$ 13,364
2007		$ 553	$ 553	$ 9,673	$ 2,764	$ 1,658	$ 663	$ 5,528	$ 5,528	$ 3,593	$ 69,094	$ 55,275	$ 27,638	$ 13,819
2008		$ 572	$ 572	$ 10,002	$ 2,858	$ 1,715	$ 686	$ 5,715	$ 5,715	$ 3,715	$ 71,443	$ 57,155	$ 28,577	$ 14,289
2009		$ 591	$ 591	$ 10,342	$ 2,955	$ 1,773	$ 709	$ 5,910	$ 5,910	$ 3,841	$ 73,872	$ 59,098	$ 29,549	$ 14,774
2010		$ 611	$ 611	$ 10,694	$ 3,055	$ 1,833	$ 733	$ 6,111	$ 6,111	$ 3,972	$ 76,384	$ 61,107	$ 30,554	$ 15,277
2011		$ 632	$ 632	$ 11,057	$ 3,159	$ 1,896	$ 758	$ 6,318	$ 6,318	$ 4,107	$ 78,981	$ 63,185	$ 31,592	$ 15,796
2012		$ 653	$ 653	$ 11,433	$ 3,267	$ 1,960	$ 784	$ 6,533	$ 6,533	$ 4,247	$ 81,667	$ 65,333	$ 32,667	$ 16,333
2013		$ 676	$ 676	$ 11,822	$ 3,378	$ 2,027	$ 811	$ 6,755	$ 6,755	$ 4,391	$ 84,443	$ 67,555	$ 33,777	$ 16,889
2014		$ 699	$ 699	$ 12,224	$ 3,493	$ 2,096	$ 838	$ 6,985	$ 6,985	$ 4,540	$ 87,314	$ 69,851	$ 34,926	$ 17,463
2015		$ 722	$ 722	$ 12,640	$ 3,611	$ 2,167	$ 867	$ 7,223	$ 7,223	$ 4,695	$ 90,283	$ 72,226	$ 36,113	$ 18,057
2016		$ 747	$ 747	$ 13,069	$ 3,734	$ 2,240	$ 896	$ 7,468	$ 7,468	$ 4,854	$ 93,353	$ 74,682	$ 37,341	$ 18,671
2017		$ 772	$ 772	$ 13,514	$ 3,861	$ 2,317	$ 927	$ 7,722	$ 7,722	$ 5,019	$ 96,527	$ 77,221	$ 38,611	$ 19,305
2018		$ 798	$ 798	$ 13,973	$ 3,992	$ 2,395	$ 958	$ 7,985	$ 7,985	$ 5,190	$ 99,809	$ 79,847	$ 39,923	$ 19,962
2019		$ 826	$ 826	$ 14,448	$ 4,128	$ 2,477	$ 991	$ 8,256	$ 8,256	$ 5,367	$ 103,202	$ 82,562	$ 41,281	$ 20,640
2020		$ 854	$ 854	$ 14,940	$ 4,268	$ 2,561	$ 1,024	$ 8,537	$ 8,537	$ 5,549	$ 106,711	$ 85,369	$ 42,684	$ 21,342
2021		$ 883	$ 883	$ 15,447	$ 4,414	$ 2,648	$ 1,059	$ 8,827	$ 8,827	$ 5,738	$ 110,339	$ 88,271	$ 44,136	$ 22,068
2022		$ 913	$ 913	$ 15,973	$ 4,564	$ 2,738	$ 1,095	$ 9,127	$ 9,127	$ 5,933	$ 114,091	$ 91,272	$ 45,636	$ 22,818
(Row 26) 2023		$ 944	$ 944	$ 16,516	$ 4,719	$ 2,831	$ 1,133	$ 9,438	$ 9,438	$ 6,134	$ 117,970	$ 94,376	$ 47,188	$ 23,594
Closure Yr 2024 **(3)**	0	**$ 976**	**$ 976**	**$ 17,077**	**$ 4,879**	**$ 2,928**	**$ 1,171**	**$ 9,758**	**$ 9,758**	**$ 6,343**	**$ 121,981**	**$ 97,584**	**$ 48,792**	**$ 24,396**
2025	1								**$ 10,090**	**$ 6,559**			**$ 50,451**	**$ 25,226**
2026	2								**$ 10,433**	**$ 6,782**			**$ 52,167**	**$ 26,083**
2027	3								**$ 10,788**	**$ 7,012**			**$ 53,940**	**$ 26,970**
2028	4								**$ 11,155**	**$ 7,251**			**$ 55,774**	**$ 27,887**
2029	5								**$ 11,534**	**$ 7,497**			**$ 57,670**	**$ 28,835**
2030	6								**$ 11,926**	**$ 7,752**			**$ 59,631**	**$ 29,816**
2031	7								**$ 12,332**	**$ 8,016**			**$ 61,659**	**$ 30,829**
2032	8								**$ 12,751**	**$ 8,288**			**$ 63,755**	**$ 31,878**
2033	9								**$ 13,185**	**$ 8,570**			**$ 65,923**	**$ 32,961**
2034	10								**$ 13,633**	**$ 8,861**			**$ 68,164**	**$ 34,082**
2035	11								**$ 14,096**	**$ 9,163**			**$ 70,482**	**$ 35,241**
2036	12								**$ 14,576**	**$ 9,474**			**$ 72,878**	**$ 36,439**
2037	13								**$ 15,071**	**$ 9,796**			**$ 75,356**	**$ 37,678**
2038	14								**$ 15,584**	**$ 10,129**			**$ 77,918**	**$ 38,959**
2039	15								**$ 16,113**	**$ 10,474**			**$ 80,567**	**$ 40,284**
2040	16								**$ 16,661**	**$ 10,830**			**$ 83,307**	**$ 41,653**
2041	17								**$ 17,228**	**$ 11,198**			**$ 86,139**	**$ 43,070**
2042	18								**$ 17,814**	**$ 11,579**			**$ 89,068**	**$ 44,534**
2043	19								**$ 18,419**	**$ 11,972**			**$ 92,096**	**$ 46,048**
2044	20								**$ 19,045**	**$ 12,380**			**$ 95,227**	**$ 47,614**
2045	21								**$ 19,693**	**$ 12,800**			**$ 98,465**	**$ 49,233**
2046	22								**$ 20,363**	**$ 13,236**			**$ 101,813**	**$ 50,906**
2047	23								**$ 21,055**	**$ 13,686**			**$ 105,274**	**$ 52,637**
2048	24								**$ 21,771**	**$ 14,151**			**$ 108,854**	**$ 54,427**
2049	25								**$ 22,511**	**$ 14,632**			**$ 112,555**	**$ 56,277**
2050	26								**$ 23,276**	**$ 15,130**			**$ 116,382**	**$ 58,191**
2051	27								**$ 24,068**	**$ 15,644**			**$ 120,339**	**$ 60,169**
2052	28								**$ 24,886**	**$ 16,176**			**$ 124,430**	**$ 62,215**
2053	29								**$ 25,732**	**$ 16,726**			**$ 128,661**	**$ 64,330**
2054	30								**$ 26,607**	**$ 17,295**			**$ 133,035**	**$ 66,518**
2055	31								**$ 27,512**	**$ 17,883**			**$ 137,559**	**$ 68,779**
2056	32								**$ 28,447**	**$ 18,491**			**$ 142,236**	**$ 71,118**
2057	33								**$ 29,414**	**$ 19,119**			**$ 147,072**	**$ 73,536**
2058	34								**$ 30,414**	**$ 19,769**			**$ 152,072**	**$ 76,036**
2059	35								**$ 31,448**	**$ 20,442**			**$ 157,242**	**$ 78,621**
2060	36								**$ 32,518**	**$ 21,137**			**$ 162,589**	**$ 81,294**
2061	37								**$ 33,623**	**$ 21,855**			**$ 168,117**	**$ 84,058**
2062	38								**$ 34,767**	**$ 22,598**			**$ 173,833**	**$ 86,916**
2063	39								**$ 35,949**	**$ 23,367**			**$ 179,743**	**$ 89,871**

Notes:

(1) Source: Bank of Canada, Monthly Series, Selected Government of Canada Benchmark Bond Yields: Long-Term as of January 31, 2004 rate.

(2)The inflation rate was calculated using the annual average non-residential building construction price index for Toronto (NRCPIT). To derive the annual inflation rate, the percentage change formula was used. =(((Year 2003 index - Year 1997 index)/Year 1997 index)/ (number of years between indices +1))*100; = (((123.8 - 100.0)/100.0)/(6+1))*100 = 3.4%

(3) Assumption: Landfill reaches capacity at 60,000 tonnes by the end of year 2023. No more waste is received at this site after December 31, 2023. Closure of the site begins in January 2024.

(4)The figure for year 2004 is the current cost valued in 2004 dollars. The value for year 2005 is calculated using the formula: value from the previous year, 2004 cost * 1.034. The same formula is applied annually until the year the cost is expected to be incurred.

Bold numbers were used in Present Value Formula in column V. Economic Analysis Section, Ministry of Energy, December 2004

Table H2:Financial Assurance Calculations for Landfill: Planned Closure and Post-closure Care Items ($'s) - Used Interest Rate: 5.23% (1) and Inflation Rate: 3.4% (2)

Year	Number of Years For Discounting	Item 1PO (Operating) Yr.2024-2043	Item 1PO (Operating) Yr.2044-2053	Item 1PO (Operating) Yr.2054-2063	Item 2PO (Capital) Yr.2024 &2044	Item 3PO (Capital) Yr. 2027 &2052	Undiscounted Future Expenditures $'s	Closure Year 2024 Expenditures $'s	Interest Rate Plus 1	Annual Waste Fill (tonnes/yr)
A	**B**	**P (4)**	**Q (4)**	**R (4)**	**S (4)**	**T (4)**	**U**	**V (5)**	**W**	**X**
		P*1.034	**Q*1.034**	**R*1.034**	**S*1.034**	**T*1.034**	**Sum of bold #s**	**U/W^B**	**1+5.23%**	
2004 (Row 7)		$ 500	$ 1,500	$ 1,250	$ 7,500	$ 12,500				3,000
2005		$ 517	$ 1,551	$ 1,293	$ 7,755	$ 12,925				3,000
2006		$ 535	$ 1,604	$ 1,336	$ 8,019	$ 13,364				3,000
2007		$ 553	$ 1,658	$ 1,382	$ 8,291	$ 13,819				3,000
2008		$ 572	$ 1,715	$ 1,429	$ 8,573	$ 14,289				3,000
2009		$ 591	$ 1,773	$ 1,477	$ 8,865	$ 14,774				3,000
2010		$ 611	$ 1,833	$ 1,528	$ 9,166	$ 15,277				3,000
2011		$ 632	$ 1,896	$ 1,580	$ 9,478	$ 15,796				3,000
2012		$ 653	$ 1,960	$ 1,633	$ 9,800	$ 16,333				3,000
2013		$ 676	$ 2,027	$ 1,689	$ 10,133	$ 16,889				3,000
2014		$ 699	$ 2,096	$ 1,746	$ 10,478	$ 17,463				3,000
2015		$ 722	$ 2,167	$ 1,806	$ 10,834	$ 18,057				3,000
2016		$ 747	$ 2,240	$ 1,867	$ 11,202	$ 18,671				3,000
2017		$ 772	$ 2,317	$ 1,931	$ 11,583	$ 19,305				3,000
2018		$ 798	$ 2,395	$ 1,996	$ 11,977	$ 19,962				3,000
2019		$ 826	$ 2,477	$ 2,064	$ 12,384	$ 20,640				3,000
2020		$ 854	$ 2,561	$ 2,134	$ 12,805	$ 21,342				3,000
2021		$ 883	$ 2,648	$ 2,207	$ 13,241	$ 22,068				3,000
2022		$ 913	$ 2,738	$ 2,282	$ 13,691	$ 22,818				3,000
(Row 26) 2023		$ 944	$ 2,831	$ 2,359	$ 14,156	$ 23,594				3,000
Closure Yr 2024 **(3)**	0	**$ 976**	$ 2,928	$ 2,440	**$ 14,638**	$ 24,396	$ 362,234	$ 362,234	1.0523	
2025	1	**$ 1,009**	$ 3,027	$ 2,523	$ 15,135	$ 25,226	$ 93,335	$ 88,696	1.0523	
2026	2	**$ 1,043**	$ 3,130	$ 2,608	$ 15,650	$ 26,083	$ 96,508	$ 87,153	1.0523	
2027	3	**$ 1,079**	$ 3,236	$ 2,697	$ 16,182	**$ 26,970**	$ 126,759	$ 108,783	1.0523	
2028	4	**$ 1,115**	$ 3,346	$ 2,789	$ 16,732	$ 27,887	$ 103,182	$ 84,149	1.0523	
2029	5	**$ 1,153**	$ 3,460	$ 2,884	$ 17,301	$ 28,835	$ 106,690	$ 82,685	1.0523	
2030	6	**$ 1,193**	$ 3,578	$ 2,982	$ 17,889	$ 29,816	$ 110,318	$ 81,247	1.0523	
2031	7	**$ 1,233**	$ 3,700	$ 3,083	$ 18,498	$ 30,829	$ 114,069	$ 79,834	1.0523	
2032	8	**$ 1,275**	$ 3,825	$ 3,188	$ 19,127	$ 31,878	$ 117,947	$ 78,446	1.0523	
2033	9	**$ 1,318**	$ 3,955	$ 3,296	$ 19,777	$ 32,961	$ 121,957	$ 77,082	1.0523	
2034	10	**$ 1,363**	$ 4,090	$ 3,408	$ 20,449	$ 34,082	$ 126,104	$ 75,741	1.0523	
2035	11	**$ 1,410**	$ 4,229	$ 3,524	$ 21,145	$ 35,241	$ 130,391	$ 74,424	1.0523	
2036	12	**$ 1,458**	$ 4,373	$ 3,644	$ 21,863	$ 36,439	$ 134,825	$ 73,130	1.0523	
2037	13	**$ 1,507**	$ 4,521	$ 3,768	$ 22,607	$ 37,678	$ 139,409	$ 71,858	1.0523	
2038	14	**$ 1,558**	$ 4,675	$ 3,896	$ 23,375	$ 38,959	$ 144,148	$ 70,608	1.0523	
2039	15	**$ 1,611**	$ 4,834	$ 4,028	$ 24,170	$ 40,284	$ 149,050	$ 69,380	1.0523	
2040	16	**$ 1,666**	$ 4,998	$ 4,165	$ 24,992	$ 41,653	$ 154,117	$ 68,174	1.0523	
2041	17	**$ 1,723**	$ 5,168	$ 4,307	$ 25,842	$ 43,070	$ 159,357	$ 66,988	1.0523	
2042	18	**$ 1,781**	$ 5,344	$ 4,453	$ 26,720	$ 44,534	$ 164,775	$ 65,823	1.0523	
2043	19	**$ 1,842**	$ 5,526	$ 4,605	$ 27,629	$ 46,048	$ 170,378	$ 64,679	1.0523	
2044	20		**$ 5,714**	$ 4,761	**$ 28,568**	$ 47,614	$ 208,548	$ 75,234	1.0523	
2045	21		**$ 5,908**	$ 4,923		$ 49,233	$ 186,099	$ 63,799	1.0523	
2046	22		**$ 6,109**	$ 5,091		$ 50,906	$ 192,426	$ 62,689	1.0523	
2047	23		**$ 6,316**	$ 5,264		$ 52,637	$ 198,969	$ 61,599	1.0523	
2048	24		**$ 6,531**	$ 5,443		$ 54,427	$ 205,734	$ 60,528	1.0523	
2049	25		**$ 6,753**	$ 5,628		$ 56,277	$ 212,729	$ 59,475	1.0523	
2050	26		**$ 6,983**	$ 5,819		$ 58,191	$ 219,961	$ 58,441	1.0523	
2051	27		**$ 7,220**	$ 6,017		$ 60,169	$ 227,440	$ 57,425	1.0523	
2052	28		**$ 7,466**	$ 6,222		**$ 62,215**	$ 297,388	$ 71,354	1.0523	
2053	29		**$ 7,720**	$ 6,433			$ 243,169	$ 55,445	1.0523	
2054	30			**$ 6,652**			$ 250,106	$ 54,192	1.0523	
2055	31			**$ 6,878**			$ 258,610	$ 53,250	1.0523	
2056	32			**$ 7,112**			$ 267,403	$ 52,324	1.0523	
2057	33			**$ 7,354**			$ 276,494	$ 51,414	1.0523	
2058	34			**$ 7,604**			$ 285,895	$ 50,520	1.0523	
2059	35			**$ 7,862**			$ 295,616	$ 49,641	1.0523	
2060	36			**$ 8,129**			$ 305,667	$ 48,778	1.0523	
2061	37			**$ 8,406**			$ 316,059	$ 47,930	1.0523	
2062	38			**$ 8,692**			$ 326,805	$ 47,096	1.0523	
2063	39			**$ 8,987**			$ 337,917	$ 46,277	1.0523	
							$ 7,938,588	**$ 2,958,525**		

Notes:

(1) Source: Bank of Canada, Monthly Series, Selected Government of Canada Benchmark Bond Yields: Long-Term as of January 31, 2004 rate.

(2)The inflation rate was calculated using the annual average non-residential building construction price index for Toronto (NRCPIT).

To derive the annual inflation rate, the percentage change formula was used. =(((Year 2003 index - Year 1997 index)/Year 1997 index)/ (number of years between indices +1))*100; = (((123.8 - 100.0)/100.0)/(6+1))*100 = 3.4%

(3) Assumption: Landfill reaches capacity at 60,000 tonnes by the end of year 2023. No more waste is received at this site after December 31, 2023. Closure of the site begins in January 2024.

(4)The figure for year 2004 is the current cost valued in 2004 dollars. The value for year 2005 is calculated using the formula: value from the previous year, 2004 cost * 1.034. The same formula is applied annually until the year the cost is expected to be incurred.

(5)The value for year 2024 in column V is the same value as the value in year 2024 in column U ($362,234); no discounting, since "year zero".

Bold numbers were used in Present Value Formula in column V. Economic Analysis Section, Ministry of Energy, December 2004

Table H2: Financial Assurance Calculations for Landfill: Planned Closure and Post-closure Care Items ($'s) - Used Interest Rate: 5.23% (1) and Inflation Rate: 3.4% (2)

Year	Number of Years For Discounting	Cumulative Waste Fill (tonnes/yr)	FA accumul. for Closure/ Post-Closure Care Cost	FA accumul. for Contingency Costs	Cumulative FA Balance: Closure/Post Closure, Yr 2004 to Yr 2023	Cumulative FA Balance: Closure/Post Closure, Yr 2024 to Yr 2063	Cumulative FA Balance: Contingency, Yr 2004 to Yr 2063	FA Balance AE
A	**B**	**Y (4)** **Y+X**	**Z (5)** **Y7...Y26/Y26*V68**	**AA (5)** **.5*Y7...Y26*(123.8/100)**	**AB (5)** **Same as Z**	**AC (6)** **AC*W-U**	**AD(5) (7)** **Same as AA**	**Yr. 2003-2023 AB+AD** **Yr. 2024-2063 AC+AD**
2004 (Row 7)		3,000	$ 147,926	$ 1,857	$ 147,926		$ 1,857	$ 149,783
2005		6,000	$ 295,853	$ 3,714	$ 295,853		$ 3,714	$ 299,567
2006		9,000	$ 443,779	$ 5,571	$ 443,779		$ 5,571	$ 449,350
2007		12,000	$ 591,705	$ 7,428	$ 591,705		$ 7,428	$ 599,133
2008		15,000	$ 739,631	$ 9,285	$ 739,631		$ 9,285	$ 748,916
2009		18,000	$ 887,558	$ 11,142	$ 887,558		$ 11,142	$ 898,700
2010		21,000	$ 1,035,484	$ 12,999	$ 1,035,484		$ 12,999	$ 1,048,483
2011		24,000	$ 1,183,410	$ 14,856	$ 1,183,410		$ 14,856	$ 1,198,266
2012		27,000	$ 1,331,336	$ 16,713	$ 1,331,336		$ 16,713	$ 1,348,049
2013		30,000	$ 1,479,263	$ 18,570	$ 1,479,263		$ 18,570	$ 1,497,833
2014		33,000	$ 1,627,189	$ 20,427	$ 1,627,189		$ 20,427	$ 1,647,616
2015		36,000	$ 1,775,115	$ 22,284	$ 1,775,115		$ 22,284	$ 1,797,399
2016		39,000	$ 1,923,041	$ 24,141	$ 1,923,041		$ 24,141	$ 1,947,182
2017		42,000	$ 2,070,968	$ 25,998	$ 2,070,968		$ 25,998	$ 2,096,966
2018		45,000	$ 2,218,894	$ 27,855	$ 2,218,894		$ 27,855	$ 2,246,749
2019		48,000	$ 2,366,820	$ 29,712	$ 2,366,820		$ 29,712	$ 2,396,532
2020		51,000	$ 2,514,746	$ 31,569	$ 2,514,746		$ 31,569	$ 2,546,315
2021		54,000	$ 2,662,673	$ 33,426	$ 2,662,673		$ 33,426	$ 2,696,099
2022		57,000	$ 2,810,599	$ 35,283	$ 2,810,599		$ 35,283	$ 2,845,882
(Row 26) 2023		60,000	$ 2,958,525	$ 37,140	$ 2,958,525		$ 37,140	$ 2,995,665
Closure Yr 2024 (3)	0					$ 2,596,292	$ 37,140	$ 2,633,432
2025	1					$ 2,638,743	$ 37,140	$ 2,675,883
2026	2					$ 2,680,241	$ 37,140	$ 2,717,381
2027	3					$ 2,693,658	$ 37,140	$ 2,730,798
2028	4					$ 2,731,355	$ 37,140	$ 2,768,495
2029	5					$ 2,767,514	$ 37,140	$ 2,804,654
2030	6					$ 2,801,937	$ 37,140	$ 2,839,077
2031	7					$ 2,834,410	$ 37,140	$ 2,871,550
2032	8					$ 2,864,703	$ 37,140	$ 2,901,843
2033	9					$ 2,892,569	$ 37,140	$ 2,929,709
2034	10					$ 2,917,747	$ 37,140	$ 2,954,887
2035	11					$ 2,939,954	$ 37,140	$ 2,977,094
2036	12					$ 2,958,889	$ 37,140	$ 2,996,029
2037	13					$ 2,974,230	$ 37,140	$ 3,011,370
2038	14					$ 2,985,634	$ 37,140	$ 3,022,774
2039	15					$ 2,992,733	$ 37,140	$ 3,029,873
2040	16					$ 2,995,136	$ 37,140	$ 3,032,276
2041	17					$ 2,992,424	$ 37,140	$ 3,029,564
2042	18					$ 2,984,153	$ 37,140	$ 3,021,293
2043	19					$ 2,969,846	$ 37,140	$ 3,006,986
2044	20					$ 2,916,621	$ 37,140	$ 2,953,761
2045	21					$ 2,883,062	$ 37,140	$ 2,920,202
2046	22					$ 2,841,419	$ 37,140	$ 2,878,559
2047	23					$ 2,791,057	$ 37,140	$ 2,828,197
2048	24					$ 2,731,295	$ 37,140	$ 2,768,435
2049	25					$ 2,661,414	$ 37,140	$ 2,698,554
2050	26					$ 2,580,644	$ 37,140	$ 2,617,784
2051	27					$ 2,488,172	$ 37,140	$ 2,525,312
2052	28					$ 2,320,915	$ 37,140	$ 2,358,055
2053	29					$ 2,199,130	$ 37,140	$ 2,236,270
2054	30					$ 2,064,038	$ 37,140	$ 2,101,178
2055	31					$ 1,913,377	$ 37,140	$ 1,950,517
2056	32					$ 1,746,044	$ 37,140	$ 1,783,184
2057	33					$ 1,560,867	$ 37,140	$ 1,598,007
2058	34					$ 1,356,605	$ 37,140	$ 1,393,745
2059	35					$ 1,131,940	$ 37,140	$ 1,169,080
2060	36					$ 885,474	$ 37,140	$ 922,614
2061	37					$ 615,725	$ 37,140	$ 652,865
2062	38					$ 321,122	$ 37,140	$ 358,262
2063	39					$ 0	$ 37,140	$ 37,140

Notes:

(1) Source: Bank of Canada, Monthly Series, Selected Government of Canada Benchmark Bond Yields: Long-Term as of January 31, 2004 rate.

(2)The inflation rate was calculated using the annual average non-residential building construction price index for Toronto (NRCPIT).

To derive the annual inflation rate, the percentage change formula was used. =(((Year 2003 index - Year 1997 index)/Year 1997 index)/ (number of years between indices +1))*100; = (((123.8 - 100.0)/100.0)/(6+1))*100 = 3.4%

(3) Assumption: Landfill reaches capacity at 60,000 tonnes by the end of year 2023. No more waste is received at this site after December 31, 2023. Closure of the site begins in January 2024.

(4)The value for year 2004 in column Y is the same value as the value in year 2004 in column X. (3,000 tonnes) For years 2005 and beyond in column Y, cumulative total = column Y (value from previous year) +column X (value from current year) for example, cumulative total for year 2012 = column Y value from year 2011 + column X value from year 2012.

(5)For years 2005 and beyond, the Financial Assurance values for closure, post-closure care and contingency costs are estimates only because i) future fill rates may change from year to year and ii) future NRCPIT indices are unknown. The Financial Assurance amounts will be revised at least every 3 years by the Regulated party once the rates are known for the years in question.

(6)The value in year 2024 is calculated using the formula, column AB (value for year 2023) - column U (value from current year). For years 2025 and beyond, the values in column AC are calculated using the formula, column AC (value from previous year) * column W which is the interest rate (value from current year)- column U (value from current year), for example value for year 2032 = column AC value for 2031* column W for year 2032 - column U for year 2032.

(7)The value in year 2024 remains constant throughout the contaminating lifespan unless the financial assurance amount is used. If an amount is used, it is required to be replaced within 6 months or as otherwise required by the Program Director.

Bold numbers were used in Present Value Formula in column V. Economic Analysis Section, Ministry of Energy, December 2004

Appendix I

Financial Assurance Refund/Disbursement Form

Ministry of the Environment

Ontario

FINANCIAL ASSURANCE REFUND/ DISBURSEMENT FORM

Type or print clearly.

Payable to:	Amount $
For the purpose of:	

Disposition of Cheque	Name	Telephone No.		Cheque required by:
❑ Mail to ❑ Deliver to ❑ To be picked up by	Address			mm dd yy Asap
	City	Postal Code		

Branch/Region	Section	
Name of Requestor	Position Title	Date
Approved by Branch/Regional Director (or designee)	Signature	Date

Responsibility Code	Function Code	Standard Account	Project Code	Amount $	Amount ¢	Invoice No.	Invoice Date mm dd yy	Certificate of Approval No.
0000		05101						
		05104						

Appendix J

Definitions

Definitions

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activity – a specific action, e.g., top soil application, installation of a leachate collection or treatment facility, groundwater monitoring, long-term monitoring, storage or security, etc. that is required by a condition of an order or approval.

approval – as defined in section 131 of the EPA (which includes OWRA approvals) – means program approval, certificate of approval or provisional certificate of approval, and includes a permit or approval issued by a Director under the *Ontario Water Resources Act*, but does not include an approval under Part X of the EPA. Where applicable, approval also refers to certificate of property use issued under section 168.6 of the EPA.

bearer bond – a form of negotiable security issued and payable to anyone with physical possession of that security. Interest and principal are payable to the holder regardless of whom it was originally issued. Coupons are attached to the bond and each coupon represents a single interest payment. The holder submits a coupon, usually semi-annually, to the issuer or paying agent to receive payment. Market trends indicate that bearer bonds are being phased out in favour of registered bonds. Bearer bonds are a form of transferable bonds.

bearer form – also called "negotiable security." The opposite of registered form. Ownership is determined by physical possession of the security. The holder of the bond is the owner. Physical certificates exist. Bearer or negotiable bonds are desirable for Financial Assurance because they can be converted to cash very quickly.

Business and Fiscal Planning Branch (BFPB) – the name of this branch may change from time to time. Reference should be made to the Ministry organization chart for the current name.

contaminating life span – as defined in Ontario Regulation 232/98 - Landfilling Sites, as amended from time to time. (The period of time, after closure, in years, from the expected year of closure until the site finally produces contaminants at concentrations that are below levels which have unacceptable health or environmental effects.)

contingency costs – are costs for unexpected activities or equipment installations which may be incurred in the future. The costs could be recurring and/or one-time capital costs for such items as construction, operation, maintenance and replacement of works identified in the regulated parties' contingency plans.

cost – or a cost item may be a one-time (capital) expenditure or it may be a recurring annual operating expenditure.

cumulative Financial Assurance balance schedules – the total (or cumulative) amount of Financial Assurance required each year during the planning period.

date of closure – defined as the first year of the contaminating life span.

Economic Analysis Section (EAS) – a section in the Strategic Policy Branch of the Ministry of Energy which provides economic analytical services to the Ministry of the Environment. The section was originally the Economic Services Branch of the Ministry of the Environment. The name of this group may change from time to time.

environmental measures – as defined in sections 131 and 132 of the EPA.

EPA – refers to Ontario's *Environmental Protection Act*.

Financial Assurance – means one or more of the mechanisms listed in section 131 of the EPA by which one party guarantees or obtains a guarantee of its performance to another party (such as the government). It is not considered a financial penalty.

forms of Financial Assurance – include standard, non-standard or unacceptable forms. Financial Assurance may also be classified as either cash or non-cash forms.

guarantor – a third party, such as a surety company, which will issue a surety bond or a similar type of Financial Assurance.

impaired Financial Assurance – means that the sufficiency or accessibility of the Financial Assurance provided by the regulated party is uncertain in some way. If the Financial Assurance is in a non-cash form, it may need to be converted to cash to be used by the Ministry to fulfil the terms and conditions in an order or approval.

Indemnification Agreement – one party in a business contract agrees to pay the other party for any losses that the other party incurs in the proposed venture.

inflation rate – the rate at which price levels rise. Nominal or current values expressed in dollars include the effects of inflation. Real values expressed in dollars exclude the inflation rate. Inflation rates are used to inflate future costs to obtain expected future nominal values. Inflation rates are based on construction price indices rather than the consumer price index.

letter of credit – a document issued by a bank which assures that the bank will make available to the beneficiary the amount agreed to by both parties, in compliance with the terms and conditions of the documentary credit agreement. It is a very secure method of ensuring payment.

letter of guarantee – a letter of guarantee is an irrevocable commitment by a bank to pay a business' debt under certain circumstances.

long-term project – when the planning period of the order or approval is four full years or more and when certain future costs are known to be required.

marketable security – is any security that can be easily converted into cash. Such securities will generally have highly liquid markets allowing the security to be sold at a reasonable price very quickly.

Ministry – refers to the Ontario Ministry of the Environment. The name may change from time to time. Reference should be made to official Government of Ontario publications for the current name.

mitigation measures – measures taken to prevent and ameliorate adverse effects (as defined in the EPA) that relate to this site during the operational period of the site and following closure of the site.

negotiable security – any security in bearer form is a negotiable security. This form can be transferred or delivered to another party without endorsements. Examples include bearer bonds and stock certificates. Negotiable securities differ from registered securities, which require endorsements in order for ownership to be transferred.

non-standard forms of Financial Assurance – the Program Director, with assistance from Legal Services Branch and Business and Fiscal Planning Branch staff assistance, should consider and review these forms to determine acceptability. The following are examples of non-standard forms of Financial Assurance:

a) any security or collateral accepted by the Program Director;
b) agreements, contracts or other non-standard forms of Financial Assurance with conditions stated in the order or approval;
c) insurance policies;
d) Guaranteed Investment Certificates (GICs) reissued payable to the Ontario Minister of Finance;
e) marketable securities (apart from those mentioned in standard forms of Financial Assurance) or other negotiable securities;
f) Indemnification Agreements;
g) letters of guarantee; and

h) Qualified Environmental Trust accompanied by letter of credit, cash or bond. This form is an agreement made between two parties for the purpose of a tax benefit to the regulated party.

one-time cost items – refer to capital costs or consulting services which are incurred usually once during the planning period. One-time costs include the costs of equipment, installation of machinery and equipment, construction of buildings and other site improvements. Other one-time costs include contract services, architect services, design and engineering, construction or installation costs, laboratory testing, project management fees, etc.

operating period of a landfill – period from the first day of operation until the day that the landfill site closes.

order – as defined in section 131 of the EPA (which includes OWRA orders) – means an order by the Director under the EPA, and includes an order, notice, direction, requirement or report made by a Director under the *Ontario Water Resources Act*, but does not include an order under section 136 (order for performance of environmental measures) of the EPA. If Financial Assurance is required on a pesticides matter, Ministry staff would have to include it in a preventative or remedial order under section 17 or 18 of the EPA.

OWRA – refers to the *Ontario Water Resources Act*.

performance bond – a surety bond issued by an insurance or surety company to guarantee satisfactory completion of a project by a contractor.

planning period – depending on the type of order or approval, planning periods for a landfill consist of the time between the day the site starts receiving waste until the end of the contaminating life span. For waste processing or transfer facilities, the planning period extends from the day that the Ministry issues an approval for the facility until the day that the site has completed all required clean-up and remediation procedures. The planning period of an order to implement abatement projects, extends from the day that the Ministry issues an order until the day that all compliance actions are completed to the satisfaction of the Director.

present value – the worth of a future stream of costs (or revenues) in terms of their value at the estimated date of closure.

$$\text{PV Cost}(n+1) = \sum(\text{sum of})\ [F(n) \div (1+r)^n]$$

where,

n = year 0, 1, 2, 3, 4, 5, ..., N

year 0 = base year: in the case of landfills, year of site closure, when discounting

year N = final year of planning period (or of contaminating life span for landfills)

F(n) = future (inflated) capital and operating costs

PV Cost(n+1) = present value of future capital and operating costs in year n+1

r = discount rate

For example, the PV of $1,000 in year 10 at a 5% discount rate:

$$\text{PV Cost}(9+1) = \$1,000 \div (1.05)^9$$

$$= \$1,000 \div 1.55133$$

$$= \$645$$

Program Director – Ministry of the Environment staff member appointed by the Minister of the Environment under section 5 of the EPA or the OWRA as a legislative "director," and is responsible for administrating different sections of the environmental statues and for developing, issuing and enforcing an order or approval. A Program Director is normally a Ministry of the Environment staff member working for the Environmental Assessment and Approvals Branch or for a Regional Office. The legislative director is not necessarily an administrative director of a branch or region of the Ministry. Investigations and Enforcement Branch has a current list of program directors appointed by the Minister.

recurring costs – refer to costs associated with the operation, maintenance and monitoring of equipment, buildings and the site, including the costs for labour, materials, ongoing consultant services, etc.

registered form – the opposite of bearer form. Ownership does not relate to physical possession of a security, but instead relates to who is registered with the issuer. The issuer or agent records and keeps ownership information such as name and address on file. Registered form bonds are not acceptable for Financial Assurance purposes, as some bonds require endorsement or power of attorney for the ownership to be transferred.

regulated party – a company, a public agency or a person who is subject to an order, an approval or a regulation and must provide Financial Assurance or who may be expected to provide Financial Assurance under an order or approval or who has or intends to apply for an approval.

saleable material – as defined in Regulation 347 - General – Waste Management, refers to municipal waste, hazardous waste or liquid industrial waste, other than used or shredded or chipped tires, transferred by a generator for direct transportation to a site,

a) to be wholly used at the site in an ongoing agricultural, commercial, manufacturing or industrial process or operation used principally for functions other than waste management if the process or operation does not involve combustion or land application of the waste, or

b) to be promptly packaged for retail sale to meet a realistic market demand, or

c) to be offered for retail sale to meet a realistic market demand.

security – a security is an investment instrument, other than an insurance policy or fixed annuity, issued by a corporation, government, or other organization.

short-term project – when the planning period of the order or approval is less than four years and when the need to implement future compliance activities is not certain.

standard forms of Financial Assurance – are acceptable and do not require Ministry review. The following are standard forms of Financial Assurance:

a) cash;
b) irrevocable letters of credit;
c) surety bonds; and
d) negotiable securities issued by or guaranteed by provincial or federal government.

surety bond – a bond issued by an entity on behalf of a second party, guaranteeing that the second party will fulfill an obligation or series of obligations to a third party. In the event that the obligations are not met, the third party will recover its losses via the bond. Examples of surety bonds include: performance bond, bid bond, payment bond, etc.

transferable bond – a bond whereby ownership can be transferred from one party to another. Transferable bonds can either be in bearer form or registered form. It should be noted that Government of Canada Savings Bonds are not acceptable for Financial Assurance purposes, as these bonds are not transferable.

unacceptable forms of Financial Assurance – the following forms are unacceptable to the Ministry and Ministry staff should not accept or consider them:

a) Guaranteed Investment Certificates (GICs) which are not transferrable;

b) all bonds which are not transferrable;

c) bank accounts held by the regulated party or joint bank accounts held by the Ministry and the regulated party;

d) insurance policies for long-term projects or landfill sites; and

e) guarantees from out-of-province, off-shore firms.

Appendix K

Procedures to Obtain Non-Residential Building Construction Price Index for Toronto (NRCPIT) from Statistics Canada Website

Procedures to Obtain Non-Residential Building Construction Price Index for Toronto (NRCPIT) from Statistics Canada Website

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Regulated parties are to follow the instructions noted below to obtain the Annual Average Non-Residential Building Construction Price Index for Toronto (NRCPIT) from the Statistics Canada's website.

(1) Go to the Statistics Canada website address, http://www.statcan.ca/start.html. Type "non-residential construction price index" in the "search the website" box and click once on the search button. Avoid typing any abbreviations in the search box because the search command does not recognize them.

(2) To derive the NRCPIT annual average for a desired year, search the list for the first three quarter documents released in the desired year and the last quarter document released in the following year. These release dates are: May, August, November and February.

(3) Click once on the documents which have the correct date and "non-residential building construction price index" in the title.

(4) When in the document, scroll down to the Non-Residential Building Construction Price Index table and extract the figure for Toronto.

(5) Use the four indexes to calculate the annual average. For example, to derive the annual average NRCPIT for 2003, data from the following release dates are used:

- First quarter 2003 rate is published during mid May (12 - 16), 2003 = 122.2;
- Second 2003 quarter rate is published during mid August (12 - 16), 2003 = 123.7;
- Third 2003 quarter rate is published during mid November (12 - 16), 2003 = 124.2; and
- Fourth 2003 quarter rate is published during mid February (12 - 16), 2004 = 125.2.

$$\text{Annual average index} = (122.2+123.7+124.2+125.2) \div 4 = 123.8$$

This index will then be used along with the 1997 index to calculate the inflation rate as per the formula noted in Section 6 of the Guideline.

CANADIAN PROVINCIAL REPORT—QUEBEC

1. Background and History

1.1 Mineral and Mining Sector

Approximately twenty mineral substances are currently mined in Quebec. Quebec is a major producer of iron, zinc, nickel, copper, and precious metals such as gold and silver. Quebec also extracts the following non-metallic minerals: chrysotile, graphite, ilmenite, mica, salt, silica, sulfur, steatite, peat, limestone, cement, industrial stone, clay products, as well as sand and gravel. The value of shipments (metallic and non-metallic minerals) from Quebec in 2010 reached $6.8 billion dollars Canadian (CDN), while mining investments totalled $2.5 billion CDN, of which $ 483 million CDN accounts for exploration and deposit appraisal expenditures. More than 16,000 direct jobs are generated in exploration, extraction, and primary processing activities. In addition, the mining sector also provides the equivalent of 14,000 indirect jobs to support the industry (e.g., professional services, machinery manufacturers).

1.2 Petroleum Sector

Quebec currently does not produce oil and gas in significant commercial quantities, but has sedimentary basins favourable to hydrocarbon accumulation that cover approximately 12 percent of the province or 200,000 square kilometres. The rocky formations of Quebec's basins are contemporary of those of important oil basins in Western Canada and Appalachia (Pennsylvania, Michigan, New York, or Ontario), and certain sedimentary areas are similar to prolific basins of the United States.

The level of exploration for hydrocarbon resources in Quebec is one of the lowest in the world. When taking into account that the first exploration well was drilled in Gaspésie in 1860, the annual average drilling is fewer than three wells per year. Oil and gas companies have recently discovered that it is possible to produce shale gas (natural gas trapped in shale rock) in Quebec.

2. Regulatory Structure

2.1 Regulatory Agency Structure

The Ministère du Développement Durable, de l'Environnement et de la Lutte Contre les Changements Climatiques (Ministry of Sustainable Development, Environment and the Fight Against Climate Change, previously the Ministry of Environment and Wildlife) and the **Ministère de l'Énergie et des Resources Naturelles (Ministry of Energy and Natural Resources, previously the Ministry of Natural Resources)** jointly administer statutes and regulations governing mining site rehabilitation.

2.2 Statutory and Regulatory Framework

2.2.1 Minerals and Mining Sector

Quebec's Mining Act and the regulations under it include provisions that require mining companies to rehabilitate the areas affected by their activities. The provisions cover extraction and exploration activities that require a specified amount of earth-moving work and mine tailings sites. By law, companies are required to file a site rehabilitation plan and to provide financial guarantees.

The government has published guidelines to inform proponents of how the rehabilitation plan is to be presented, its technical content, and the general mining site rehabilitation requirements involved. Quebec's oil and gas resources are currently legislated under the province's mining rules and regulations.

The Quebec government announced in 2010 that it would establish a single regulatory regime that would create a fiscal and legal framework for investing in oil and gas in Quebec.

2.2.2 Petroleum Sector

Regulations respecting petroleum, natural gas, and underground reservoirs have been established under the Mining Act. These regulations provide requirements for licensing geophysical surveys, well drilling, completion, conversion, and closing. They also provide for application for temporary or permanent closure that requires payment of $2,000 CDN and $2,500 CDN, respectively. The regulations also provide requirements for leases for exploration, use, and underground storage of petroleum and gas.

Under An Act to Limit Oil and Gas Activities (2011, Chapter 13), oil and gas activities in the St. Lawrence River upstream of Île d'Anticosti and on the islands situated in that part of the river are prohibited.

3. Security/Financial Assurance

A financial guarantee is a key component of a rehabilitation plan and the essence of the amendments to the Mining Act (M-13.1, R.I, Sections 96.5 to 96.16). A company that expects to use or that is already using a storage area must provide the Ministry of Energy and Natural Resources with a financial guarantee once its rehabilitation plan has been approved. The amount of the guarantee must cover 70 percent of the estimated cost of restoring the storage site. The number of annual payments depends on the type of activity (exploration or extraction) and the expected duration of the activity (maximum of 15 years).

A company that owns several properties to which the measures apply and that must make several separate payments in the same year may provide a single financial guarantee to cover the total amount of the guarantees on each of the properties. The guarantee is repaid when the work provided for in the rehabilitation plan has been completed. It may, however, be repaid in part or increased following a reassessment of the cost of the work. The Ministry of Energy and Natural Resources may also repay the guarantee if it authorizes a third party to take responsibility for rehabilitating the site.

Furthermore, following the amendment to Section 232.7 of the Mining Act in 2003, the Ministry of Energy and Natural Resources may require payment of the total guarantee should the operator’s financial situation deteriorate or should the anticipated duration of the operator’s activities be reduced.

Once the rehabilitation work has been completed in accordance with the approved plan and there is no further risk of acid mine drainage from the site, the Ministry of Energy and Natural Resources will issue a certificate stating that the company is released from its obligations. The same certificate will be issued if a third party agrees to take responsibility for rehabilitation.

3.1 Mining Sector

The security requirements apply to the holders of mining rights who carry out advanced exploration work on land in the public or private domain. More specifically, the requirements cover:

- Excavation that involves earth-moving work affecting 10,000 cubic metres or more of loose soil or an area of 10,000 square metres or more;
- Sampling work on 500 metric tonnes or more of mineral substances
- Work carried out on substances located in storage sites (especially mine tailings sites)
- Underground exploration work, such as the driving of drifts, the pumping out of shafts, and the hoisting of mineral substances
- The preparation of storage sites.

The law also applies to all companies extracting substances from public or private land in Quebec. The general obligations cover all mineral substances except petroleum, natural gas, brine, and surface mineral substances. They therefore apply to:

- All activities relating to ore extraction, especially the removal and transportation of ore, the sinking of shafts, the driving of drifts and ramps, ore crushing, and dry storage
- All activities relating to the processing or ore or tailings, especially preparation, enrichment (excluding refining and pelletization), and the separation of solids from liquids
- All work relating to the preparation of storage zones,
- All work carried out on mine tailings.

Every company carrying out mining activities subject to the Mining Act must submit a rehabilitation plan to the **Ministry of Energy and Natural Resources** which, after consulting with the Ministry of Sustainable Development, Environment, and the Fight Against Climate Change may approve the plan and its implementation schedule. The Ministry of Energy and Natural Resources may, where necessary, request that additional research or studies be completed before approving the plan. The rehabilitation plan must be submitted to the Department before the beginning of the work subject to the provisions of the Act. In particular, the plan must contain the following information:

- A description of the site and of completed or projected mining activities
- A description of the rehabilitation work scheduled to take place during the extraction process, where circumstances permit
- A description of the rehabilitation and restoration work scheduled to take place once mining has ceased
- A stage-by-stage implementation schedule
- An assessment of the cost of the rehabilitation work
- A description of the financial guarantee provided for the restoration of storage sites.

The rehabilitation plan must be revised every 5 years, but in certain cases, the Ministry of Energy and Natural Resources may require more frequent revisions or may order a revision, in particular following a change in mining activities or the introduction of new technologies, or if the operator wishes to change the plan. The revised plan must be submitted to the Ministry of Energy and Natural Resources for approval.

The proponent must describe in detail the rehabilitation cost (in current dollars) by activity detailed description of the fees related to each activity including administration and design fees as if all work was carried out by a third party. The cost of progressive rehabilitation and the monitoring program must be included. The cost of rehabilitation must be based on quantifiable information available when the plan is submitted. As the plan is reviewed, increasingly precise details of cost estimate must be provided.

The provisions of the Act allow the Ministry of Energy and Natural Resources to intervene when the storage areas of an abandoned mine site create a hazard. In such a case, the Ministry of Energy and Natural Resources can require a person or company that produced mine tailings before March 9, 1995 to prepare a rehabilitation plan for the land affected by the mine tailings and the work defined in the plan to be carried out within the prescribed time.

The Mining Act requires the holders of mining rights to carry out statutory work on their mining sites in order to retain their rights. Work to rehabilitate or restore mine sites carried out in accordance with a rehabilitation plan is recognized as statutory work for the purposes of renewing a mining right.

The Quebec government also recognizes measures taken to secure a mine site, as prescribed by regulation, and to prevent any damage that may result from a cessation of activities. This type of work includes filling in trenches, installing a concrete slab over a shaft or chute, and installing a fence around an open work site.

3.1.1 Calculation of Financial Assurance

The amount of the guarantee depends on the rehabilitation plan and corresponds to 70 percent of the estimated cost of restoring accumulation areas. The accumulation areas targeted by the financial guarantee are: the tailings pond, including sedimentation and polishing ponds, waste rock piles, mining waste piles, concentrate/ore stock piles, and mine water ponds.

Where exploration is expected to last 1 year or less, the total guarantee must be submitted within 15 days of the rehabilitation plan's approval if accumulation areas are to be built specifically for this activity. Where exploration is expected to last more than 1 year, and where the rehabilitation plan has been approved, the guarantee must be submitted in annual payments, with the first payment corresponding to the estimated cost of the rehabilitation work for activities already being carried out or to be carried out during the year. Each subsequent annual payment must correspond to the estimated cost of rehabilitation work to be carried out that year.

For mining activities, the number of annual payments of the guarantee is established based on their expected duration as noted in Table 3.1-1. Operators will be informed of the payment schedule once the rehabilitation plan has been approved. The expected duration of mining activities is determined when the plan is approved or revised.

Where applicable, the first payment of the guarantee is payable within 15 days of the rehabilitation plan's approval. Where mining activities are expected to last less than 10 years, a payment may be postponed and added to the next annual payment. No postponement is allowed in the last 2 years of payment.

Where mining activities are expected to last 10 years or more, two consecutive payments may be postponed. No further postponement is possible until the postponed payments have been made, and no postponement is possible in the last 3 years of payment.

Under Section 232.5 of the Mining Act, the Minister may, under certain conditions, require advance payment of all or part of the financial guarantee.

Because some mining sites are co-owned, partners may underwrite the guarantee according to the percentage of their holding in the mine. The partners may also choose to appoint an operator to be responsible for submitting the financial guarantee.

Table 3.1-1 Schedule of Annual Payments per $1 of the Guarantee (Established under Section 96.5 of the Mining Act)

Expected duration of activities	Payments														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	1.00														
2	1.00	-													
3	.250	.750	-												
4	.111	.333	.556	-											
5	.063	.187	.313	.437	-										
6	-	.063	.187	.313	.437	-									
7	-	.040	.120	.200	.280	.360	-								
8	-	.028	.083	.139	.194	.250	.306	-							
9	-	.020	.061	.102	.143	.184	.225	.265	-						
10	-	-	.020	.061	.102	.143	.184	.225	.265	-					
11	-	-	.016	.047	.078	.109	.141	.172	.203	.234	-				
12	-	-	.012	.037	.062	.086	.111	.136	.161	.185	.210	-			
13	-	-	.010	.030	.050	.070	.090	.110	.130	.150	.170	.190	-		
14	-	-	-	.010	.030	.050	.070	.090	.110	.130	.150	.170	.190	-	
15	-	-	-	.008	.025	.041	.058	.074	.091	.107	.124	.141	.157	.174	-

The amount of the financial guarantee may be increased or reduced based on:

a) The progress of the rehabilitation work compared to the schedule

b) The amount of rehabilitation work completed when the mine is shut down

c) Whether or not the proponent intends to use more economical rehabilitation methods.

Section 232.1 of the Mining Act allows the Ministry of Energy and Natural Resources to carry out the rehabilitation work and recover the cost from the guarantee if the proponent fails to carry out the rehabilitation work.

The guarantee must remain in effect until a certificate of release provided for in section 232.10 of the Act is issued. It may be issued if the person has carried out the rehabilitation work outlined in the rehabilitation pan and to the Ministry of Energy and Natural Resources' satisfaction or a third party assumes the obligations in the rehabilitation plan.

3.1.2 Acceptable Forms of Security/Financial Assurance

The guarantee must be provided in the form of:

- A cheque made out to the Minister of Finance of Quebec;
- Bonds issued or guaranteed by Quebec or another Canadian Province, by Canada, or by a Canadian municipality with a minimum market value equal to the amount of the guarantee required;
- A guaranteed investment certificate or a term deposit certificate issued to the Minister of Finance by a bank, savings, and credit union or trust company. The certificate must have a 12-month minimum term, be automatically renewable until the issue of a certificate of release provided for in section 231.10 of the Mining Act, and must not include any restrictions to its redemption during the term;
- An irrevocable, unconditional letter of credit issued to the Quebec government by a bank, savings, and credit union or trust company;
- A security or guarantee policy issued to the Quebec government by a company legally authorized to do so;
- A security provided by a third party to the Quebec government with the person providing the security also providing an immovable hypothec of the first rank whose net liquidation value is at least equal to the amount of the guarantee required;
- A trust constituted as per the Civil Code of Quebec and meeting the following requirements:
  - The purpose of the trust is to ensure completion of the work provided for in the rehabilitation and restoration plan.
  - The Minister of Finance and the person referred to in section 232.1 of the Mining Act are joint beneficiaries of the trust.
  - The trustee is a bank, savings, and credit union or trust company.
  - The trust patrimony is composed only of sums in cash, or bonds, or certificates of the same type as those referred to in subparagraphs 2 and 3.

The person referred to in Section 232.1 of the Mining Act may choose to submit the guarantee in any of the above forms, depending on the rehabilitation objectives (progressive, short-term, or long-term rehabilitation) and his financial capacity. The lending institutions are responsible for evaluating a company’s capacity to pay the guarantee and the financial risk involved.

3.2 Petroleum Sector

The Mining Act applies to oil and gas development.

3.2.1 Calculating Security/Financial Assurance for Idle and Abandoned Wells

The methods used for calculating mining securities are the same for the petroleum sector in Quebec.

3.2.2 Acceptable Forms of Security/Financial Assurance

The same forms of financial assurance accepted for the mining sector are accepted for the petroleum sector.

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CANADIAN PROVINCIAL REPORT—SASKATCHEWAN

1. Background and History

1.1 Mineral Resources

Mining represents the third largest industry in the Province of Saskatchewan producing a diverse array of mineral resources including potash, uranium, coal, gold, salt, silica sand, sodium sulphate and clay. In fact, with mineral production valued at $ 7.2 billion dollars Canadian (CDN) in 2013, Saskatchewan ranks third in terms of mineral production value within Canada (Government of Saskatchewan Ministry of Economy 2014a) and is considered a major producer of several mineral resources world-wide including uranium, potash, and sulphate.

Saskatchewan is a key player in uranium mining with one of the richest uranium deposits in the world in the in the Athabasca basin and mines located at Rabbit Lake and Key Lake. Saskatchewan accounts for over 15 percent of uranium production worldwide, second only to Kazakhstan. The province produces 100 percent of Canada's uranium (Government of Saskatchewan Ministry of Economy 2014c).

Saskatchewan is also home to the world's richest deposits of potash with 10 of Canada's 11 potash mines located in the province. It is the largest potash producer in the world with the potential to supply world demand for potash at current levels for the next several hundred years (Government of Saskatchewan Ministry of Economy 2014c). Additionally, the province produced 8.8 million tons of potash with a sales value of $ 6.0 billion CDN (Government of Saskatchewan Ministry of Economy 2014c).

The province ranks sixth in the world in the production of sodium sulphate, which is the product of alkaline lakes found in the southern part of the Saskatchewan. The province is the third largest producer of coal in Canada with three active coal mines in the southeast part of the province. Two are in the Estevan/Bienfait area and one is near Coronach area. Currently, Saskatchewan has 5.1 billion tons of coal resources in the province (Government of Saskatchewan Ministry of Economy 2014c).

With the discovery of one of the largest clusters of kimberlite bodies in the world, Saskatchewan could become a significant diamond producer in the future as well (Government of Saskatchewan Ministry of Economy 2014c). Saskatchewan's Fort à la Corne area has one of the world's largest kimberlite fields with the surface area of some kimberlites exceeding 200 hectares and a potential of more than 34 million carats.

1.2 Hydrocarbon Resources

Saskatchewan has 10 trillion cubic feet of natural gas and is Canada's third largest producer of natural gas, representing about 20 percent of total Canadian production (Government of Saskatchewan Ministry of Economy 2014b). The primary areas of oil and gas reserves and production are found along the western border in the Beacon Hill, Kindersley, and Hatton areas. In 2010 there were over 20,000 producing natural gas wells in Saskatchewan (Government of Saskatchewan Ministry of Economy 2014b). To date, approximately seven trillion cubic feet of natural gas have been produced in the province. In 2011, Saskatchewan's oil and gas industry contributed $12.7 billion CDN in sales and employed 33,200 person years in direct and indirect employment (2012 Provincial Auditor's Report, Lysyk 2012).

Saskatchewan is the second largest oil producing province in Canada, accounting for 15 percent of total crude oil production, and is the sixth largest oil producing jurisdiction in North America (Government of Saskatchewan Ministry of Economy 2014b). Heavy and light crude oils are produced from the Lloydminster, Kindersley-Kerrobert, Swift Current, and Weyburn-Estevan areas. In 2010 there were over 26,000 active wells in the province and producing approximately 5.5 billion barrels of oil to date. Heavy oil upgrader facilities that transform bitumen (extra heavy oil) into synthetic crude oil are located in Regina and Lloydminster. Oil and gas production activities have contributed $14.2 billion CDN to the provincial economy in 2013 (Government of Saskatchewan Ministry of Economy 2014b).

As of as of July 31, 2012, there were 87,000 oil and gas wells and 5,300 facilities located in Saskatchewan. These wells and facilities are owned by 447 licensees with the largest 10 licensees owing 65,000 wells and 3,200 facilities (Lysyk 2012). Of these 87,000 wells, 58,000 were active (producing), 24,000 were non-producing, and 5,000 were abandoned (Lysyk 2012). In the 2012 Provincial Auditor's Report, estimates there are approximately 700 wells and facilities where the licensees have ceased operation or can longer be located (Lysyk 2012). The Ministry of Economy also estimates that there are over 5,800 wells that have been inactive for 10 years or more (Lysyk 2012). Additionally, current estimates of overall future environmental clean-up costs of existing oil and gas wells could total $ 3.6 billion CDN.

2. Regulatory Structure

2.1 Governmental Agencies

In May 2012, the Ministry of the Economy was created to bring a more integrated approach to the province's economic growth. The Ministry's mission is to advance economic growth to generate wealth and opportunity in Saskatchewan and its mandate is to advance and regulate responsible resource development; develop, attract, and retain skilled workers while enhancing economic growth and competitiveness in the province. The Ministry of Environment is responsible for ensuring air, water, and lands are developed in an environmentally sound manner. Site assessment and restoration are within the Ministry of Environment's jurisdiction as well.

2.1.1 Mining Sector

The Minerals, Lands, and Policy Division, within the Ministry of the Economy manages mineral and forestry development. It manages the province's mineral taxation policy, geological services, energy policy, and Crown mineral lands. In addition to administering mineral, energy, and forestry sector development, The Mineral, Lands, and Policy Division also promotes growth in these sectors. However, the Ministry of Environment is responsible for decommissioning, reclamation, and remediation (DR&R) activities related to mines.

2.1.2 Petroleum Sector

The Ministry of the Economy's Petroleum and Natural Gas Division is responsible development of Saskatchewan's oil and gas resources and decommissioning of oil and gas wells and facilities.

2.1.3 Surface Land and Water Resources

Both the mining and the petroleum sectors require access to water and surface lands in order to explore, develop, and produce resources. The Ministry of Environment is responsible for the issuance of surface leases, including those obtained for both mining and oil and gas activities, on Crown lands. Contaminated sites are within the jurisdiction of the Ministry of Environment

The Water Security Agency leads the management of the province's water resources to ensure safe drinking water sources and reliable water supplies for economic, environmental, and social benefits.

2.2 Statutory and Regulatory Framework

Environmental protection is governed broadly by the Environmental Management and Protection Act (EMPA 2002), which provides powers to the Ministry of Environment to set and enforce regulations. The 2002 version of the EMPA is expected to be replaced by 2010 version of the statute in the fall of 2014. The amended EMPA will clarify the Minister of Environment's powers, empower the Environmental Code, and perform other housekeeping items. This update to the Act doesn't change the overall financial assurance requirements for mining operations. However, it will allow financial assurances to be placed on any industrial activity in the province (e.g., downstream oil and gas, which are also in the Ministry of Environment's purview).

During the environmental assessment phase of a project, plans for the decommissioning and reclamation of the proposed project must be included in the document. An initial plan is usually presented at the feasibility stage of a project with the understanding that a Preliminary Decommissioning Plan, a Preliminary Decommissioning Cost, and financial assurance will be in place prior to the permit to operate being issued.

2.2.1 Mining Sector

Mining and mineral resources are regulated through the Saskatchewan Mineral Resources Act (Chapter M-16.1), the Saskatchewan Energy and Mines Act (Chapter E-9.10001) and the Saskatchewan Crown Minerals Act (Chapter C-50.2). However, mine closure and DR&R activities are regulated under the EMPA.

The Mineral Industry Environmental Protection Regulations (MIEPR), which were promulgated under the EMPA define the requirements for review and approval of mine decommissioning and reclamation plans (DRP) and for the establishment of an assurance fund to ensure the completion of DR&R activities for a given mine site. An application for approval of a DRP and an assurance fund is to include:

- Time frame for decommissioning and reclaiming the mining site
- Description of the proposed methods, procedures, and timeframes for site monitoring
- Cost estimate for implementing the DRP and long-term site monitoring
- Assurance fund proposal to include:
  - Management and administration of the assurance fund
  - Release of all or portions of the assurance fund during the decommissioning and reclamation of the mining site

2.2.2 Petroleum Sector

Oil and gas is regulated through the Oil and Gas Conservation Act (Government of Saskatchewan 1978) and the Pipeline Act. The Oil and Gas Conservation Act regulates most aspects of upstream oil and gas activity, including decommissioning, reclamation, and administration of orphaned sites. Orphaned wells and facilities are defined as sites where responsible licensees cannot be located or do not have the financial means to pay for the cleanup costs. Abandoned wells and facilities, in contrast, are those sites that have reached their end of life and are in the process of being dismantled and restored.

3. Securities/Financial Assurances

3.1 Financial Assurance/Security Requirements

3.1.1 Mining Sector

Under Section 12 of the MIEPR, a mine licensee cannot operate a mine, mill, or pollution control facility until it has a DRP, an assurance fund proposal that has been approved by the Minister of Environment, and established the assurance fund to the Minister of Environment's satisfaction. Mines, mills, and associated pollution control in operation prior to the promulgation of the MIEPR were required to obtain an approved DPR and assurance fund under Section 13 of the MIEPR as well.

In order to obtain approval for a DRP, a mine operator must submit an application to the Minister of Economy and the application must include the information identified in Section 14.2.a of the MIEPR.

- Timeline for decommissioning and reclamation activities

- A detailed description of proposed methods and procedures for the decommissioning and reclamation activities, including long-term monitoring
- Cost estimate including all reclamation activities, including post reclamation monitoring activities
- Proposal for an assurance fund that complies with Section 15 of the MIEPR; the proposal must include how the fund will be managed and administered as well as how the assurance fund will be released in whole or part during decommissioning and reclamation of the mining site.

Section 16.1 of the MIEPR requires the mine operator review its DRP and assurance fund based on the following schedule:

- At least every five years
- Whenever required by the minister, where in the minister's opinion, established assurance fund
- At the time of the permanent closure of a pollutant control facility, mine, or mill unless a review pursuant to this section (Section 16) has been conducted within the 12 months preceding the permanent closure

Section 16.2 of the MIEPR requires the mine operator to provide the results of each review to the Minister of the Economy within 60 days of completing the review. For mine operators that fail to complete a review of its DRP and assurance fund based on the schedule described above, the Minister may require the mine operator to engage an approved third-party to complete the review per Section 16.3 of the MIEPR

Per Section 18 of MIEPR,:a person who wishes to close a mine permanently must:

- Advise the Ministry of Environment in writing at least 60 days before commencing the permanent closure
- Implement any DRP approved by the Ministry according to the time frames set out in the plan

Section 19.2 of MIEPR allows the Minister of Environment to use an assurance fund posted by a mine operator under the following circumstances:

- Enforce any security, call in, cash, or redeem any security or other instrument, or take any other action that the minister considers necessary to realize on the assurance fund
- Require that all or part of the assurance fund be used to decommission and reclaim all or part of the mining site for which the assurance fund was approved in accordance with the decommissioning and reclamation plan approved for that mining site or in any other manner the minister considers appropriate

Where the money exceeds the cost of the decommissioning and reclaiming the mining site, the Ministry of Environment will refund any excess amount per Section 20 of MIEPR:

- Where it is necessary to re-establish an assurance fund for the balance of the decommissioning and reclamation work for that mining site, to the person who has an approved decommissioning and reclamation plan for that mining site
- Where the assurance fund is no longer required, to:
  - The person specified in the DRP as the person entitled to any excess amount where the fund is no longer required
  - Any person at the direction of the person mentioned in the DRP
  - Any person at the direction of a court with jurisdiction concerning the matter

Section 21 of MIEPR addresses situations in which an assurance fund is deemed to insufficient to cover total costs of decommissioning and reclaiming a mining site by authorizing the Ministry of Environment to collect additional funds from the mine operator who holds an approved DRP for that mining site.

Under Section 22 of MIEPR, a mine operator must apply in writing to the Ministry of Environment to be released, in whole or in part, from the requirements or obligations set out in DRP. The application is to include the following information and material:

- Detailed analysis and evaluation of monitoring data and observations from the decommissioning and reclaiming and post-decommissioning and post-reclaiming monitoring program that demonstrates compliance with requirements set out in the approval
- A list and assessment of remaining environmental liabilities

3.1.2 Petroleum Sector

Section 115 of the Oil and Gas Conservation Act Regulation empowers the Ministry of the Economy to require a security deposit be submitted by an oil and gas operator as a condition for receiving an operating license. The amount of security is approved by the Minister of the Economy. These security deposits are held in trust in the Oil and Gas Orphan Fund (Orphan Fund) by the Ministry of the Economy. Oil and gas securities can range from zero to several million dollars. These securities are held in trust to prevent a licensee from transferring (or selling) uneconomic wells and facilities to companies or individuals who do not have economic means to pay for the cleanup costs. In the event that existing licensees becomes bankrupt or cannot be located in the future, it forfeits its security deposits. The funds are used by the Ministry of the Economy to cover the costs of cleaning up their wells and facilities (Government of Saskatchewan 1978).

In addition to the securities that are held in trust in the Orphan Fund, the Ministry of the Economy is authorized to charge an annual levy on each well under Section 119 of the Oil and Gas Conservation Act Regulations to cover the costs associated with orphan wells and facilities. The levies vary by well type and are published in regulation. Orphan wells and facilities are those historic sites for which a responsible party cannot be located or who do not have the financial means to pay for the cleanup costs. The cleanup of these sites is managed by the Ministry of the Economy (Government of Saskatchewan 1978).

An oil and gas operator must successfully complete site decommissioning and reclamation work and have the Ministry of Economy declare site remediation is complete through the Acknowledgement of Reclamation Program (AOR) in order to receive a refund of its security deposit. This process involves the Ministry of the Economy performing a Detailed Site Assessment of the well or well facility site. If the site passes this assessment, an AOR application must be submitted within six months to receive an AOR certificate from the Ministry of the Economy per Section 56.3 of the Oil and Gas Conservation Regulations (Government of Saskatchewan 1978). The AOR does not release a licensee from any unforeseen long-term environmental liabilities arising from its wells and facilities. The certificate reduces a licensee's assessed abandonment and reclamation liabilities under the LLR program and hence the security deposits and levies that they must pay to the Ministry of the Economy. Land owners can also bring action against a producer whom they feel has not successfully remediated a site on their land.

3.2 Calculation of Financial Assurance Security

3.2.1 Mining Sector

3.2.1.1 Mining Sector except Potash Industry

The Guidelines for Northern Mine Decommissioning and Reclamation provides general guidance concerning planning for mine site closure, but does not provide a detailed description of how the costs associated with implementing a DRP are estimated (Saskatchewan Ministry of the Environment 2008). The guidance does, however, indicate that the cost estimate should assume a third-party would implement the activities identified in the DRP. Under the MIEPR, the mine operator must provide a proposal for an assurance fund, which is reviewed by the Minister of Environment.

While the Ministry of Environment does not provide detailed guidance concerning how a mine operator must determine the amount of security it is required to post as an assurance fund, the MIEPR does allow a mine operator to request a review of its DRP and assurance fund proposal under certain, specified circumstances. Section 17.1 of MIEPR allows a mine operator who obtains an approval for a DRP and an assurance fund under Section 12 of MIEPR to forward a request to the Minister of Environment

- No more than once each year if the request is for a revision that would reduce the obligations or projected costs

- At any time if the request is for a revision that would increase the obligations or projected costs
- At any time while a permanent closure is underway

Where a revision that increases the projected costs of the DRP is approved, the person who obtained the approval shall make, by an approved date, any changes to the assurance fund that are required by the revision. Where a revision that decreases the projected costs of the decommissioning and reclamation is approved, changes to the assurance fund can be approved if those changes do not adversely affect the assurance fund.

3.2.1.2 Potash Industry

The potash industry, which largely pre-dates the requirements for conducting environmental assessments or posting financial bonds, are an exception to the security requirements described above. Until 2013, the industry had less than a total of $10 million dollars CDN in place, which is barely sufficient to accomplish the surface reclamation work for one site, let alone the eight sites in operation today. In late 2013, the potash industry agreed to post $10 million CDN in cash for each company and start a decommissioning fund that would increase each year until it was 100 percent funded at the predicted end of mine lives, 50 to 100 years in the future.

3.2.2 Petroleum Sector

3.2.2.1 Security Deposits

The Oil and Gas Conservation Act and Regulations govern most aspects of upstream oil and gas activity, including decommissioning and reclamation and orphaned sites. The regulations detail the responsibilities of all parties. A letter of credit or any other form of security provided for in the regulations is required in an amount determined by the Minister of Economy, for the purpose of ensuring that the person's obligations pursuant to this *Ac*t, the regulations or a licence with respect to the suspension, abandonment, restoration, remediation or reclamation of wells, facilities and the sites of wells and facilities are satisfied. The basic security requirements are $10,000 upon application to be held in trust by the government (**Government of Saskatchewan 1978**).

Section 117 of the Oil and Gas Conservation Regulation establishes the Licensee Liability Rating Program (LLR), which the Ministry of the Economy uses to determine if any additional security funds are required for the operation (**Government of Saskatchewan 1978**). The LLR is designed to help prevent the rapid increase of orphaned well and facility liabilities in the future and to help ensure oil and gas operators or licensees pay for the future cleanup of its wells and facilities. Although the Oil and Gas Conservation Regulation outlines the general framework for the LLR Program, the Ministry of the Economy published Guideline PD-G01: LLR Program Guideline to provide additional details to licensees regarding how individual LLRs are calculated in 2013 (**Government of Saskatchewan Ministry of Economy 2013**).

The LLR is calculated as a ratio between a licensee's deemed assets and its deemed liabilities. Deemed assets are calculated based on the monetary value of oil and/or gas production of the wells or well facilities covered by an individual license plus the value of the exiting security deposit. Deemed liabilities are based on the estimated cleanup costs for the given wells of well facilities. An oil and gas operator is required to provide additional security funds if its LLR drops below 1.0, which occurs when a licensee's deemed assets are less than its deemed liabilities. The Ministry of the Economy estimates an LLR for each licensee of an oil, gas, or service well and upstream oil and gas facility on a monthly basis and at the time of well and facility transfers.

3.2.2.2 Orphan Levies

Annual orphan levies are paid each fiscal year as required by Section 20.98.c of the Oil and Gas Conservation Act and Section 119 of the Oil and Gas Conservation Act Regulations based on a ratio between a licensee's liability and the sum of all licensees liabilities combined multiplied by the annual budget required for the Ministry of the Economy to carry out DR&R activities for orphan sites.

$$Orphan\ Fund\ Levy = \frac{A}{B}\ X\ Annual\ Budget$$

Where:

A	is the licensee's liability for all facilities, wells and un-reclaimed sites licensed to the licensee, as calculated at a date and in a manner specified by the Minister of the Department of the Economy;
B	is the sum of the oil and gas industry's liability for all licensed facilities, wells and un-reclaimed sites, as calculated at a date and in a manner specified by the Minister of the Department of the Economy; and
Annual Budget	is the amount that is required to conduct work specified in subsection 118(1) for a fiscal year as determined by the minister after any consultation with the fund advisory committee appointed pursuant to Section 120 of the Oil and Gas Conservation Act Regulation that the Minister of the Department of the Economy considers necessary.

3.3 Forms of Financial Assurance/Security Accepted

3.3.1 Mining Sector

Under the Mineral Industry Protection Regulations an assurance fund may consist of:

- Cash
- Checks and other similar negotiable instruments

- Government bonds, government guaranteed bonds, debentures, term deposits, certificates of deposit, trust certificates, or investment certificates
- Guarantees, irrevocable letters of credit, irrevocable letters of guarantee, performance bonds, or surety bonds
- Security interests in goods, documents of title, securities, chattel papers, instruments, moneys, intangibles, or interests that arise from an assignment of accounts that secure the performance of a decommissioning and reclamation plan approved by the Minister
- Any other financial instrument or security that is acceptable to the Minister;
- Anything mentioned in clauses a to f together with an agreement for staged decommissioning and reclamation, with each stage of the decommissioning and reclamation to be completed in accordance with that agreement
- Any combination of the forms described above

3.3.2 Petroleum Sector

A letter of credit or any other form of security provided for in the regulations is accepted as financial assurance for oil and gas operations.

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CANADIAN PROVINCIAL REPORT—YUKON

1. Background and History

1.1 Mining and Minerals

Mineral exploration in the Province of Yukon has a long history of discoveries, starting with the Klondike Gold Rush in 1898 (Mining Yukon 2014). The Yukon hosts significant deposits of gold, copper, lead, zinc, silver, tungsten, and coal. Exploration of the Yukon has uncovered more than 80 mineral deposits, some of which are of world-class stature. One of the world's largest iron ore deposits is located in northeastern Yukon. Five significant volcanogenic massive sulphide deposits have been discovered over the last decade, and more will undoubtedly be found. The Mactung and Cantung deposits are believed to contain about 15 percent of the world's known tungsten reserve.

Some of Yukon's most notable mines include the Whitehorse Copper Mine, the United Keno Hill Mine, which at one time was Canada's largest producer of silver, and the Faro Mine. In 2007 and 2008, mineral exploration companies invested a total of $227 million Canadian dollars (CDN) in the Yukon. The Minto Mine, opened in 2007, was Yukon's first producing mine in 11 years. Many other mining projects, such as Wolverine, near Ross River, are poised to begin production.

Placer (a Spanish word meaning “a place where gold can be recovered from gravel”) deposits occur in several areas in Yukon, though historically, most of the mining has taken place near Dawson City. This area is particularly favourable for placer deposits because it is in the un-glaciated part of Yukon.

1.2 Hydrocarbon Resources

The Yukon boasts an abundance of oil and gas resources, most of which remains largely unexplored due to its remoteness. However, this is expected to change within the next decade due to major infrastructure projects such as the proposed MacKenzie Gas Project. There are eight onshore basins with an estimated potential of 17 trillion cubic feet of gas and 800 million barrels of oil. In addition, there is an offshore potential of 40 trillion cubic feet of gas and 4.5 billion barrels of oil (Yukon Department of Energy, Mines and Resources 2011 ort). Similar to Alaska, several oil and gas companies are actively exploring arctic drilling and piloting technology in the Yukon, which could open up offshore oil plays beneath the ice (Government of Yukon 2014). With resource potential estimated at 67 trillion cubic feet of natural gas and 7 billion barrels of oil in the Mackenzie Delta/Beaufort Sea Basin, interest in petroleum exploration and development in the Beaufort Sea region has increased significantly. Work commitments in excess of $3 billion CDN have been made since 2007.

2. Regulatory Structure

2.1 Devolution

Yukon became the first territory to take over land and resource management responsibilities as the final major step in the territory's devolution process when the Yukon Act came into effect on April 1, 2003 (Aboriginal Affairs and Northern Development Canada 2014). The Yukon Act gave the territory control over a greater variety of province-like programs, responsibilities, and powers.

Devolution is the process of transferring authority from one government to the other and is important to understanding how mineral and hydrocarbon resources are regulated in the Yukon. The process for Yukon devolution began when *The Canada Yukon Oil and Gas Accord was* signed in 1993. The Accord allowed for the administration and legislative control over oil and gas resources, including the collection of natural resource revenues derived from oil and gas resources. In 2001, another milestone was reached in devolution with the signing of The *Yukon Northern Affairs Program Devolution Transfer Agreement*. This agreement transferred responsibilities for lands, water, forestry, and mineral resources from the Government of Canada to the Government of Yukon.

In August 2012, amendments were made to resource revenue sharing arrangements under the *Yukon Northern Affairs Program Devolution Transfer Agreement* and the 1993 *Canada-Yukon Oil and Gas Accord* allowing Yukoners to benefit from arrangements similar to those recently agreed to in principle as part of Northwest Territories devolution negotiations. These amendments ensure that a greater portion of the revenues generated from the mining and resource economy in Yukon will be available for use in the territory.

2.2 Statutory and Regulatory Framework

2.2.1 Mining Sector

The Yukon Quartz Mining Act *(*Chapter 14) forms the basis for hard rock mining requirements in the Yukon. The Yukon Placer Mining Act (Chapter 13) serves as the statutory basis for gold mining requirements. In addition to these two statutes, the financial assurance may be required pursuant to the Yukon Waters Act (Chapter 19). Major hard rock mines in Yukon may also require a Type A or B Water License under the Yukon Waters Act, which requires a separate security.

When the devolution process was completed on April 1, 2003, the federal Quartz Mining Act and Placer Mining Act were superseded by the Yukon statutes. Each of these statutes has regulations associated with them that have been promulgated to regulate mining and petroleum resources in the Yukon. The regulations provide a more detailed legal framework for administering mine exploration, development, production, and rehabilitation. The Quartz Mining Land Use Regulation 2003/64 was promulgated to regulate hard rock mining in the Yukon. This regulation came into force on April 1, 2003. In order to regulate placer mining, the Placer Mining Land Use Regulation (2003/59) was promulgated and came into force on April 1, 2003.

2.2.2 Petroleum Sector

The statutory basis for oil and gas regulation in the Yukon is the Yukon Oil and Gas Act (Chapter 162). Several regulations have been promulgated to address oil and gas activities in the Yukon. These regulations include:

- Disposition Regulations 1999/147
- Geoscience Exploration Regulations 2004/156
- Oil and Gas License Administration Regulations 2004/157
- Oil and Gas Drilling and Production Regulation 2004/158
- Gas Processing Plant Regulation 2013/168

2.3 Regulatory Agencies

2.3.1 Mining

The Department of Energy, Mines, and Resources is responsible for managing and supporting the sustainable development of the Yukon's energy and natural resources. There are 11 branches within the Department; however, there are only four that are most relevant to dismantlement, reclamation, and remediation (DR&R) of mines and petroleum sites.

The Assessment and Abandoned Mines Branch leads efforts to address environmental issues at Yukon's abandoned mines. The Mineral Resources Branch regulates exploration and mining activity and encourages its development, while the Oil and Gas Resources Branch (OGRB) regulates the exploration and production of hydrocarbon resources. Geoscientific and technical information is provided to the Department of Energy, Mines, and Resources by the Yukon Geological Survey.

2.3.2 Oil and Gas

The regulatory agency for administering petroleum regulations in the Yukon is the OGRB. The OGRB's mandate is to not only encourage the development of Yukon's resource potential and emerging oil and gas industry; it is responsible for the management of these resources. The OGRB regulates oil and gas activity onshore as well as managing Yukon's interest in offshore Beaufort Sea development. The Branch is also responsible for issuing licenses and for administering oil and gas rights.

On February 7, 2015, the Yukon government entered into a services agreement with the British Columbia Oil and Gas Commission. The agreement includes the sharing of information such as guidelines and lessons learned, cooperating in the review and assessment of development programs, and working collaboratively on common issues such as trans-boundary oil and gas basins and regulation development (Government of Yukon Oil and Gas Division 2014).

3. Security/Financial Assurance

Since devolution, the Government of the Yukon is responsible for and holds securities paid by mining and petroleum resource operators in a special account.

3.1 Mining Sector

All onsite and any offsite facilities covered under a mine license issued by the Government of Yukon must be covered under a Mine Closure Plan, which must be accompanied by a security. The closure plan and security must be submitted when a mine operator applies for a mine license. Financial security held by the Yukon government for mine reclamation and closure activities is composed of an initial payment, prior to commencement of development, and a periodic adjustment to ensure that full security is held for outstanding mine reclamation and closure liability throughout the development, operation, and closure of a mine. Additional financial security may need to be provided with the updated estimate of financial assurance required for mine reclamation and closure to cover the outstanding liability costs at any time the new estimate is posted. The Government of Yukon can perform its own risk assessment and determine the amount of financial assurance required.

3.1.1 Calculation of Financial Assurance

The Government of Yukon requires that the amount of security being held for a mining operation must be able to cover the total outstanding reclamation and closure liability costs at all times. The initial amount of security required is based on the cost estimate provided with the mine closure plan and is subsequently reviewed every 24 months. Progressive reclamation may reduce the amount of financial security required. If outstanding liability increases, mine owners will provide additional financial security. The liability estimate may be prepared by an independent third party as agreed upon in advance by the mine owner and the Government of Yukon. Alternatively, the mine owner may submit an estimate for review by the Government of Yukon. Estimates for engineered structures and designs must be approved by a professional engineer licensed to practice in the Yukon.

A prescribed level of security is not provided by the Government of Yukon; rather, the amount of financial assurance required is calculated for each individual mine. In order to assist mine operators with calculating the security for a mine, the Yukon Water Resources Board has written “Reclamation and Closure Planning for Quartz Mining Projects: Plan Requirements and Closure Costing Guidance.” Specific liability estimation cost guidance is provided in Annex 2 of that document. The guidance details how direct and indirect costs can be calculated, as well as providing reclamation and closure costing tables for use in estimating the total security required. The costing tables are general and list the types of inputs that should be considered rather than specifying dollar amounts. While the statutes, regulations, and guidance documents do not provide a cost per acre or mine site required for financial assurance, it does provide a summary of the securities posted for large mine projects on its website. These securities are summarized in Table 3.1-1.

Table 3.1-1 Current Large Mine Securities Held by Government of Yukon

Project	Pursuant to Waters Act	Pursuant to Quartz Mining Act	Total Security Held
Alexco - Keno Hill Silver District Mining Operations		$4,172,850	$4,172,850
Carmacks Mining Corp.		$80,300	$80,300
Golden Predator - Brewery Creek	$795,000		$795,000
Kaminak Gold Corp.		$165,485	$165,485
Ketza River Holdings	$3,087,600	$703,371	$3,790,971
Kud Ze Kaya	$220,000		$220,000
Minto	$4,450,000	$37,521,095	$41,971,095
Sä Dena Hes		$22,600,000	$22,600,000
Selwyn Chihong Mining Ltd		$420,500	$420,500
Stratagold Corporation		$149,000	$149,000
Yukon Zinc Corporation	$64,000	$7,527,235	$7,591,235
Total Security Held	$8,616,600	$73,339,836	$81,956,436

3.1.2 Forms of Acceptable Financial Assurance.

The Government of Yukon accepts several hard forms of financial assurance for mining activities. Alternate (non-cash) forms of financial assurance may be considered for lower risk components of a project, provided these forms meet certain criteria that protect the Government of Yukon’s interests and objectives. Table 3.1-2 lists the forms of security accepted by the Government of Yukon and where applicable the type of instrument each form can take. For example, the Government of Yukon considers bank drafts and cheques to each be a subset or type of cash, rather than their own form of security.

Table 3.1-2 Form and Type of Mine Security Accepted for Mining Sector

Form	Type of Instrument/ Restrictions
Cash	Bank drafts, certified cheques, guaranteed investment certificates, term deposits, corporate bonds, certificates from other organizations outside of Canada
Letter of Credit	Irrevocable letter of credit , bank letter of guarantee
Pledge of Assets	Cannot equal total security amount.
Surety Bonds	Surety bond issued by a company licensed under the Insurance Act (Yukon) and Insurance Companies Act (Canada) in Canada.
Insurance	The insurance company must be licensed to issue insurance pursuant to the

Table 3.1-2 Form and Type of Mine Security Accepted for Mining Sector

Form	Type of Instrument/ Restrictions
	Insurance Act (Yukon) and the Insurance Companies Act (Canada). Purpose and form of the insurance should be such that the enforceable pledges of funding are used to guarantee coverage should specified reclamation and closure liabilities arise, including in the event of default by the insured.
Trust Held by Third Party	Security may be held in a trust pursuant to a trust indenture where the Government of Yukon is named as beneficiary of the trust. To be eligible to hold security on behalf of a mine owner, a third party must be a trust company licensed under the Trust and Loans Companies Act (Canada). The beneficial use of the trust must be to meet security

3.2 Securities Hydrocarbon Resources

When an application for a well license is received by the Chief Operations Officer, the Minister of Energy, Mines, and Resources shall, for the purposes of determining the amount of the initial deposit required under subsection 90(1) of the Yukon Oil and Gas Act (as amended in 2004 and 2012) in respect of the well, estimate the amount that would be incurred if the well were to be abandoned as soon as practicable after drilling operations ceased and before the rig that drilled the well was removed from the well site. For well facilities such as a gas processing plant, a security deposit is required when a license application is submitted. In addition to the security, an abandonment plan for the facility must be provided to address DR&R activities that will be completed at the end of the facility's life.

3.2.1 Forms of Security/Financial Assurance Accepted

The preferred form of security for the petroleum sector is cash, but upon approval of the Minister, another form of security for the initial well deposit may be accepted. The well deposit is held in a trust account. Under certain circumstances, the initial deposit may be furnished in installments and may specify the due dates for the installments. The amount of the bond is specific to the well license being issued. For gas processing plants and liquefied natural gas facilities, the following forms of financial assurance are accepted:

- Letter of credit
- Guarantee
- Indemnity bond
- Any other form of proof of financial responsibility satisfactory to the Minister.

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