BRITISH COLUMBIA ENERGY REGULATOR

Permittee Capability Assessment

Program Guidance

VERSION 1.3: May 2024

About the Regulator

The British Columbia Energy Regulator (Regulator) is the single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Regulator's core roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring industry complies with provincial legislation and cooperating with partner agencies. The public interest is protected by ensuring public safety, protecting the environment, conserving petroleum resources and ensuring equitable participation in production.

Vision, Mission and Values

Vision

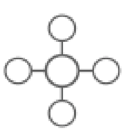
A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

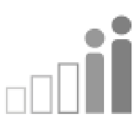
We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:

Protects public safety and the environment

Supports reconciliation with Indigenous peoples and the transition to low-carbon energy



Conserves energy resources



Fosters a sound economy and social well-being

Values

Respect is our commitment to listen, accept and value diverse perspectives.

Integrity is our commitment to the principles of fairness, trust and accountability.

Transparency is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation is our commitment to learn, adapt, act and grow.

Responsiveness is our commitment to listening and timely and meaningful action.

Additional Guidance

As with all Regulator documents, this guidance does not take the place of applicable legislation. Readers are encouraged to become familiar with the acts and regulations and seek direction from Regulator staff for clarification. Some activities may require additional requirements and approvals from other regulators or create obligations under other statutes. It is the applicant and permit holder's responsibility to know and uphold all legal obligations and responsibilities.

Throughout the document there are references to guides, forms, tables and definitions to assist in creating and submitting all required information. Additional resources include:

- Glossary and acronym listing on the Regulator's website.
- Documentation and guidelines on the Regulator's website.
- Frequently asked questions on the Regulator's website.
- Advisories, bulletins, reports and directives on the Regulator's website.
- Regulations and Acts listed on the Regulator's website.

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Manual Revisions

The Regulator is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the Energy Professionals section of the Regulator's website. Stakeholders are invited to provide input or feedback on Regulator documentation to Systems@bc-er.ca.

Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
1.0	Apr 1, 2022	Apr 1, 2022	All	First Version Released.
1.1	May, 2023	May, 2023	Chapter 5 and 6	Corrective action proportional risk factor scale updated. Corrective action work plan requirements updated. Users are encouraged to review in full.
1.2	Nov 29, 2023	Nov 29, 2023	Various	Replace BCOGC with BCER; OGAA with ERAA; new logos, references and associations.
1.3	April 30, 2024	June 1, 2024	Chapter 4	Inclusion of dormant pipelines and dormant facilities in total magnitude of liability.

Chapter 1: Overview

1.1 Purpose

This document guides users through the processes and procedures of the Regulator's Permittee Capability Assessment (PCA) program. The purpose of the PCA program is to mitigate risk and focus on reducing liability while companies are financially viable. It assists the Regulator in determining security deposits required of permit holders to protect against those who may not be capable of meeting closure obligations.

This document is not intended to replace applicable legislation; the user is encouraged to read all applicable legislation and regulation and request clarification from Regulator staff, if necessary.

1.2 Scope

This document provides information on the processes and requirements within the Regulator's legislative authorities; it does not provide information on legal responsibilities outside of the Regulator's legislative authorities. It is the responsibility of the applicant or permit holder to know and meet all of its legal responsibilities.

1.3 How to Use this Document

This document 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 PCA program, the document guides the user through PCA calculations, including the assessment of financial risk and the magnitude of liability, to security deposit requirements and dispute processes.

1.4 Common PCA Terms

Permittee Capability Assessment (PCA): A holistic assessment of each permit holder's financial and operational capability.

Level of Financial Risk: An assessment of each permit holder's corporate finances under the PCA program.

Magnitude of Liability: A measure of the magnitude of risk posed by each permit holder's total abandonment, assessment, remediation and reclamation liability cost associated with Dormant, Inactive and Marginal sites (wells, facilities, and pipelines).

Security Deposit Requirements: A summary of assessments and the processes related to required security deposits.

Dispute Process: A summary of how to make a formal dispute to a security deposit request.

Chapter 2: Permittee Capability Assessment

The PCA program objectives are to be responsive to changing industry risks; require corrective action when risk is identified; and encourage permit holders to proactively reduce liability. The PCA program will be used by the Regulator to assist in determining required security deposits for permit holders under section 30 of the Energy Resource Activities Act (ERAA). The Regulator will continually monitor and adjust the PCA program to achieve program objectives.

2.1 Risk under the PCA

The purpose of the PCA is to assess the financial risk of each permit holder's operations in British Columbia and to mitigate any identified risk while permit holders are financially viable. In practice, this risk is measured as the potential financial impact to the Orphan Site Reclamation Fund (OSRF) in the case of an insolvency or other event. Risk under the PCA is defined as the Level of Financial Risk x the Magnitude of Liability.

The Level of Financial Risk under the PCA is determined from the financial information submitted by permit holders on an annual and quarterly basis. Widely accepted financial ratios (parameters) were selected based on their ability to distinguish permit holders that are financially healthy versus those that are in distress. The selected ratios measure a company's profitability over time, their liquidity and ability to meet obligations as they come due, and the level of debt used to finance the business. For further information on the Level of Financial Risk please refer to *Chapter 3: Assessment of Financial Risk*.

The Magnitude of Liability under the PCA is based on the abandonment, assessment, remediation and reclamation liability cost associated with each permit holder's Dormant, Inactive and Marginal sites. Under the PCA, this is referred to as a permit holder's DIM Liability. Historically, sites that are Dormant, Inactive, or Marginal have accounted for nearly all orphan sites in BC. By focusing primarily on these sites, the Regulator encourages companies to expedite closure work on sites that have reached the end of their productive potential. For further information on the Magnitude of Liability, please refer to *Chapter 4: Determination of Liabilities*. To view a list of each permit holder's liabilities, please visit: Liability Management Well Report (bc-er.ca), Dormant Facility Population (bc-er.ca), Dormant Pipeline Population (bc-er.ca).

Any questions regarding the PCA program can be directed to: Liability.Management@bc-er.ca.

Chapter 3: Assessment of Financial Risk

The Regulator collects corporate financial and reserves information to assess the financial health of permit holders. The Regulator requires permit holders submit annual financial information within five (5) months from their year-end, and three (3) months from their quarter-end. For annual financial information submissions, permit holders must include audited financial statements prepared in accordance with International Financial Reporting Standards or Canadian accounting standards for private enterprises. Quarterly financial information submissions and permit holders with DIM Liability (refer to section 4.1) less than $1 million are not required to include audited financial statements. Permit holders that do not submit their annual financial information in the timeframe given will be considered high risk and assessed with corrective action requirements.

For reserves information, the Regulator requests permit holder submit annually five (5) months after year-end. For example, permit holders with a year end of December 31st, annual financial and reserves submissions will be required by May 31st.

Financial submissions are to be submitted for the permit holder's corporate entity operating in BC. For further information or questions, please contact Liability.Management@bc-er.ca.

The Corporate Financial and Reserves Submission Portal Guidance can be accessed through the Liability Management website here.

3.1 Financial Parameters

The financial information submitted annually and quarterly is analyzed to assess the level of financial risk for each permit holder. Widely accepted financial ratios (parameters) were selected based on their ability to distinguish permit holders that are financially healthy versus those that are in distress. The selected ratios measure a company's profitability over time, their liquidity, ability to meet obligations as they come due, and the level of debt used to finance the business. Ratios are calculated using the financial information submitted by permit holders through the eSubmission portal. The following five ratios are currently utilized in the assessment of financial risk:

- **Current Ratio** – Ratio of current assets over current liabilities to measure whether a company can pay their obligations as they come due.
- **Net Profit Margin (three-year Average)** – Ratio of net profit over revenues, or the percentage of income kept as profit. This is averaged over three years to smooth unusual gains/losses in a single year.
- **Interest Coverage** – A ratio of earnings over interest expense, used to determine how easily a company can pay interest on its outstanding debt.

- **Cash Flow to Debt** – A ratio of cash flows from operations over debt, which indicates how easily a company can repay its debt.
- **Debt to Equity** – A ratio of debt over equity to measure financial leverage, indicating the degree to which a company has financed its operations with borrowed money versus wholly owned funds.

Table 1 below outlines the calculation of these ratios and their respective risk ranges. These risk ranges will be reviewed annually to ensure that they are accurately modeling levels of financial risk.

Table 1 – Financial Parameter Calculations and Risk Ranges

Ratio Calculation	Very Low Risk	Low Risk	Medium Risk	High Risk	Very High Risk
$Current\ Ratio = \frac{Current\ Assets}{Current\ Liabilities}$	>=1.20	1.19 to 0.90	0.89 to 0.70	0.69 to 0.50	<0.50
$Net\ Profit\ Margin = \frac{Net\ Income}{Total\ Revenue - Royalties}$	>=0.05	0.04 to 0.00	-0.01 to -0.25	-0.24 to -0.75	<-0.75
$Interest\ Coverage = \frac{EBITDA}{Interest\ Expense}$	>=4.00	3.99 to 3.00	2.99 to 2.00	1.99 to 1.00	<1.00
$Cash\ Flow\ to\ Debt = \frac{Cash\ Flow\ from\ Ops}{Total\ Debt}$	>=0.50	0.49 to 0.35	0.34 to 0.20	0.19 to 0.10	<0.10
$Debt\ to\ Equity = \frac{Total\ Debt}{Stockholders'\ Equity}$	<=1.00	1.01 to 1.33	1.34 to 1.66	1.67 to 2.00	>2.00

3.2 PCA Scoring

Under the PCA, each financial ratio is assessed from a score of zero to 100, where zero is considered very low risk and 100 is considered very high risk. The score assessed for each ratio is based on the risk ranges outlined in Table 1 and is not based on a linear scale. The score for each ratio is scaled as follows:

- Very Low Risk = 0
- Low Risk = 0-33.3
- Medium Risk = 33.3-66.6
- High Risk =66.6-100
- Very High Risk = 100

The calculation of these scores for each ratio is shown in Table 2. Any ratio exceeding the very low or very high risk thresholds is assigned a score of zero or 100 respectively.

For the Current Ratio, Net Profit Margin, and Cash Flow to Debt please refer to the risk ranges in Table 1 to determine which equation to utilize to calculate your PCA score using the low, medium or high risk scoring.
In the case of the Interest Coverage and Debt to Equity ratios, due to the linear distribution of the ratio. across the risk ranges, a single calculation can be applied to calculate the score for low, medium or high risk ratios.

Table 2 – Calculation of PCA Scoring

Financial Ratio	Low Risk Score	Medium Risk Score	High Risk Score
Current Ratio	$= \frac{CR - 1.2}{0.9 - 1.2} \times 33.3$	$= (\frac{CR - 0.9}{0.7 - 0.9} \times 33.3) + 33.3$	$= (\frac{CR - 0.7}{0.5 - 0.7} \times 33.3) + 66.6$
Net Profit Margin	$= \frac{NPM - 0.05}{0 - 0.05} \times 33.3$	$= (\frac{NPM - 0}{-0.25 - 0} \times 33.3) + 33.3$	$= (\frac{NPM + 0.25}{-0.75 + 0.25} \times 33.3) + 66.6$
Interest Coverage	$= \frac{IC - 4}{1 - 4} \times 100$		
Cash Flow to Debt	$= \frac{CFD - 0.5}{0.35 - 0.5} \times 33.3$	$= (\frac{CFD - 0.35}{0.2 - 0.35} \times 33.3) + 33.3$	$= (\frac{CFD - 0.2}{0.1 - 0.2} \times 33.3) + 66.6$
Debt to Equity	$= \frac{DE - 1}{2 - 1} \times 100$		

Each financial ratio is weighted to generate the overall PCA score. The weighting of each ratio is as follows:

- **Current Ratio** – 30%
- **Net Profit Margin (three-year Average)** – 30%
- **Interest Coverage** – 20%
- **Cash Flow to Debt** – 10%
- **Debt to Equity** – 10%

To calculate the overall PCA score, take the score between zero and 100 for each individual ratio and multiply it by the assigned weighting. For example, Company A has the following ratio scores:

- **Current Ratio** of 0.8 yields a score of 50. 50*0.3=15
- **Net Profit Margin (three-year Average)** of -0.05 yields a score of 40. 40*0.3=12
- **Interest Coverage** of 1.0 yields a score of 100. 100*0.2=20
- **Cash Flow to Debt** – of 0.5 yields a score of 0. 0*0.1=0
- **Debt to Equity** of 1.3 yields a score of 30. 30*0.1=3
- **Overall PCA Score** – To calculate the overall PCA score, add the scoring for each ratio: (e.g. Company A: 15+12+20+0+3= 50). The resulting PCA score for Company A is 50, placing them in the middle of the medium risk range.

For further information or questions on the financial parameters and PCA scoring calculations, please contact Liability.Management@bc-er.ca.

Chapter 4: Magnitude of Liability

The Magnitude of Liability under the PCA is based on the deemed abandonment, assessment, remediation and reclamation liability cost associated with each permit holder's Dormant, Inactive and Marginal (DIM) sites. Under the PCA, this is referred to as each permit holder's DIM Liability. Historically, sites that are Dormant, Inactive, or Marginal have accounted for nearly all orphan sites in BC. By focusing primarily on these sites, the Regulator aims to incentivize companies to expedite closure work on sites that have reached the end of their productive potential.

4.1 DIM Liability

DIM liability refers to the total modelled liability cost associated with: dormant, inactive and marginal wells; plus, dormant facilities; plus, dormant pipelines, as defined below:

- Dormant Well: no or limited activity for 5 years or more as defined under Section 3 of the Dormancy and Shutdown Regulation;
- Inactive Well:no activity for 12 consecutive months, or 6 consecutive months for a Special Sour well as defined under Section 25 of the Drilling and Production Regulation); and
- Marginal Well:associated production of less than 10 Barrels of Oil Equivalent per Day
- Dormant Facility: no or limited activity for 5 calendar years or more as defined under Section 3.01 of the Dormancy and Shutdown Regulation
- Dormant Pipeline: no or limited activity for 5 calendar years or more as defined under Section 3.02 of the Dormancy and Shutdown Regulation.

To view a list of each permit holder's wells, facilities and pipelines and whether they are considered DIM Liability, please visit: Liability Management Well Report (bc-er.ca), / Dormant Facility Population (bc-er.ca) / Dormant Pipeline Population (bc-er.ca).

4.2 Deemed Liability Calculations

The Regulator's modeling for deemed liabilities continues under the PCA program. Deemed liabilities are calculated using the following equation:

Deemed Liabilities = Abandonment Cost + Assessment Cost + Remediation Cost + Reclamation Cost

Liability unit costs are assigned on the date of rig release for a well or on the leave to open date for facilities. Abandonment unit costs for wells include 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, as well as the transport of material to a suitable receiving facility. Assessment unit costs include the cost to complete site investigations to determine whether contamination is present, and if remediation is required. Remediation unit costs include the cost to address the likelihood of contaminated media, while reclamation unit costs include the replacement 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 Regulator'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 dispute is accepted.

If a well or facility contains additional contaminated media, beyond what has been considered in the standard liability unit cost, the Regulator 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 issued a Certificate of Restoration (COR) Part 1, and have not been re-entered, will not have the assessment and remediation unit cost included in the liability calculation. Wells and facilities that have been issued a COR Part 2, or wells that were abandoned before the enactment of COR requirements in 1974 have a liability value of zero. However, wells that have been re-entered or require additional remedial activities after the issuance of a COR Part 2 are included.

A 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.

4.2.1 Wells

The deemed liability for a well is defined as the estimated cost to decommission, assess, 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. A well is classified as an Oil or Condensate well if it has any history of oil or condensate production.

Using information fields that are managed in Regulator databases, a well is assigned an abandonment, assessment, remediation, and/or reclamation unit cost, which is linked to its well authorization (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 and sites that are canceled with surface disturbance, are included in the deemed liability calculation.

4.2.2 Facilities

The deemed liability for a facility is defined as the estimated cost to decommission, remove equipment, assess and 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 Regulator databases, a facility is assigned an abandonment, assessment, remediation and reclamation liability, which is linked to its Facility ID (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 deemed liability calculation. Other stations include injection stations, water hubs, shared facilities, tank terminals and pump stations. 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.

4.2.3 Pipelines

The deemed liability for a pipeline is defined as the estimated cost to deactivate and abandon the pipeline. Pipeline liability unit costs use factors such as remoteness, fluid type, length and outside diameter to identify risk factors that increase closure costs.

Using information fields that are managed in Regulator databases, a pipeline is assigned deactivation liability per kilometre (km) and abandonment liability, which is linked to its project number and segment number. The total deemed pipeline liability for a permit holder is the sum of all project number and segment number liabilities.

4.2.4 Large Facilities

A facility with a design capacity exceeding 10,000 e^3m^3 per day is considered a "Large Facility" under the PCA program. The Regulator may request permit holders complete and submit a site-specific liability assessment ("SSLA") for any permitted Large Facility. The SSLA will be used by the Regulator to determine if increased security with respect to the decommissioning and restoration liability costs associated with the Large Facility. See section 6.2 – Site Specific Liability Assessments for further information on SSLAs.

4.2.5 Shared Pad Liability

Where wells and facilities share a common lease/pad, assessment, remediation, and reclamation liability will be calculated using a revised method, rather than using the standard costs in the deemed liability model. The deemed assessment and reclamation liability for a multi-well shared pad will be equal to the largest assessment and reclamation unit cost for one of the wells or facilities constructed on the site, plus 20% of the assessment and reclamation unit cost applicable to each remaining well on the site. The deemed remediation liability will be equal to the largest remediation unit cost for one of the wells or facilities constructed on the site, plus 50% of the remediation 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.

4.3 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 Regulator. 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 Regulator 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 Regulator gathers information on the environmental status of the site. If information is insufficient to determine environmental risk and revise the liability cost, the Regulator may request that a site-specific liability assessment be completed by the permit holder (see 6.1 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 Regulator 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 Regulator 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 Regulator, 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 the Regulator 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 Regulator 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.

Chapter 5: Corrective Action Requirements

The PCA will target companies with moderate or high levels of financial risk for corrective action. The Regulator will identify potentially at-risk permit holders annually and at the time of any permit transfers. Quarterly financial information will be utilized to identify companies that may be experiencing changing levels of risk over the course of the year. Permit holders who do not provide the requested financial and reserves information will be assessed as very high risk and assigned a PCA score of 100.

Note, a permit holder that becomes high-risk for reasons not identified by financial review, at any time, may be subject to provide security and/or receive other compliance and enforcement orders at the request of the Regulator in accordance with ERAA.

Following each annual assessment of the financial and reserves submissions from each permit holder, the Regulator will engage with permit holders to provide corrective action requirements based on the corrective action calculation (section 5.1). For most permit holders with year ends of December 31st, these discussions will take place annually in May and June. Permit holders will have 12 months, up to June 30th the following year, to take corrective action through the submission of security deposits and/or the completion of liability reduction work. The Regulator will require a plan following issuance of corrective action (section 5.2). These plans will include a clear plan for how and when any liability reduction commitments are to be completed and/or provide a phased security payment schedule to meet corrective action. Note, the Regulator may require a security deposit payments as part of a plan for corrective action in cases where inadequate security is held for a permit holder.

5.1 Calculation of Corrective Action Requirements

Corrective action requirements are calculated based on the Magnitude of Liability and Level of Financial Risk of each permit holder, as well as any security deposits already held by the Regulator. To calculate corrective action requirements, a Proportional Risk Factor (PRF) is utilized. The PRF follows a linear scale between a minimum and maximum parameter. Under the PCA, the Regulator is focusing on addressing the risks associated with permit holders displaying a moderate or high level of financial distress., the PRF scales from zero to 100% for permit holders with a moderate or high level of financial risk. This will be reviewed on an annual basis to ensure identified risks are being adequately addressed.

To calculate each permit holder's PRF, use the following equation:

$$Proportional\ Risk\ Factor = (Overall\ PCA\ Score - 33.3) \times 0.03$$

The maximum PRF is 100% and the minimum PRF is 0%. As a result, low risk scores of below 33.3 would result in a PRF of 0% and high risk scores above 66.6 would result in a PRF of 100%.

Once the PRF for a permit holder is calculated, then corrective action requirements are calculated as follows:

$$Corrective\ Action\ Requirement = (PRF \times Magnitude\ of\ Liability) - Security\ Deposit$$

For example, if Company A has a PCA score of 65, total DIM Liability of $10 million and a security deposit of $1 million, then the following calculations would be used to determine corrective action requirements:

$$Proportional\ Risk\ Factor = (65 - 33.3) \times 0.03 = 95.1\%$$

$$Corrective\ Action\ Requirement = (0.951 \times \$10{,}000{,}000) - \$1{,}000{,}000 = \$8{,}510{,}000$$

In this example, Company A would have corrective action requirements of $8,510,0000 to be addressed through liability reduction activities and the payment of security deposits over the next 12 months.

Corrective action requirements will be capped at $10 million.

5.2 Submitting a Corrective Action Plan

An Excel spreadsheet outlining a company's Well, Facility and Pipeline modelled liability costs (Abandonment, Assessment, Remediation and Reclamation) will be provided at the time PCA results (Corrective Action Requirements) are emailed. To be clear, liability reduction work will contribute to Corrective Action Requirements based on the associated decrease in the modeled liability, not the actual expenditure. Liability reduction for wells, facilities and pipelines can contribute to corrective action. The primary stage gates for liability reduction are as follows:

- Wells: downhole abandonment, cut and cap, assessment (as per DSR), remediation (COR Part 1), and reclamation (as per DSR).
- Facilities: decommissioning (NOI to Remove Facility), assessment (as per DSR), remediation (COR Part 1), and reclamation (as per DSR).
- Pipelines: deactivation, and abandonment (abandoned or removed).

The spreadsheet will be drawn from the Regulator's database and dated the day it was pulled. Note, the database may not represent completed work up to the labelled date.

The liability costs reflected in this sheet will be considered as the starting point for costs that can be reduced by work completed in a corrective action plan. If there is liability reduction work that has been completed prior to this date, not yet 'zero'd out' in the spreadsheet (likely due to a backlog of reports under review by the Regulator), that liability cost will contribute to the corrective action plan.

When providing a corrective action plan, the Regulator requests using the spreadsheet provided to highlight the liability costs associated with any wells, facilities, pipelines where there is planned liability reduction work to be completed in the time period (as well as completed work – not yet reflected in this spreadsheet). Please add a column showing the cost reduction total, with a sum of all cost reduction totals at the bottom.

Example - Provided Spreadsheet

WA Num	Well Name	AD Num	Status	Abandonment Liability	Assessment Liability	Remediation Liability	Reclamatior	Total Liability
44444	abc	100001234	DRIL/UND/U	$ 7,500.00	$ 4,000.00	$ 15,000.00	$85,000.00	$ 111,500.00
55555	xyz	100006789	DRIL/UND/U	$ 7,500.00	$ 4,000.00	$ 15,000.00	$85,000.00	$ 111,500.00

Example:

Your company plans to abandon (cut and cap) Well# 44444. The liability associated with that work is $7,500 and, you plan to Abandon and provide a Certificate of Restoration Part 1 for Well# 55555, where the total liability associated with that work is $26,500. Please zero out these numbers, making sure to note the total reduction ($34,000) as your corrective action plan.

Example - Corrective Action Plan (to be returned to the Commission)

WA Num	Well Name	AD Num	Status	Abandonment Liability	Assessment Liability	Remediation Liability	Reclamatior	Total Liability	Total Reduction
44444	abc	100001234	DRIL/UND/U	$ -	$ 4,000.00	$ 15,000.00	$85,000.00	$ 104,000.00	$ 7,500.00
55555	xyz	100006789	DRIL/UND/U	$ -	$ -	$ -	$85,000.00	$ 85,000.00	$ 26,500.00
Sum of total reduction costs=									$ 34,000.00

Please email the spreadsheet back to Liability.management@bc-er.ca with a summary noting you plan to reduce liability by x amount.

In addition to, or instead of, liability reduction work, security may be supplied in the form of cash or irrevocable letter of credit.

If your planned liability reduction work does not meet your required corrective action amount the difference will be invoiced and payable in the form of Cash or Letter of Credit on the last invoice for that PCA period (June to June) As noted, in some cases the Regulator may review liability reduction work in your corrective action plan and request a portion of the plan is made up of security.

5.2 New Permit Holders

Permit holders who are applying for their first well or facility permit or permit transfer may be required to submit a 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.

5.3 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 security requirement review. The applicant or permit holder involved in the transaction may be required to submit a security deposit as calculated by the Regulator. Security may be required against deemed liability of dormant sites being transferred where dormant, inactive and marginal site liability outweigh productive site liability being transferred. Security deposits are to be submitted within 30 days from the date of request.

5.4 Return of Security Deposits

At the request of a permit holder, the Regulator may return all or part of a security if the Regulator is satisfied that all or part of the security is not required to secure the permit holder's obligations under ERAA or the permit holder's permits or authorizations. The two avenues available for the return of security are:

1. The Regulator may, upon request by a permit holder, return all or part of a security deposit when the permit holder has completed liability reduction activities (decommissioning or obtained a

   Certificate of Restoration Part 1 or Part 2) and the security is not required to secure the permit holder's obligations.
2. The security deposit will be returned in full when all the restoration obligations associated with a permit holder's sites are brought to closure.

Permit holders can make the request to:

Liability.Management@bc-er.ca

The Regulator accepts security deposits submitted in cash or as an irrevocable letter of credit in a format that is satisfactory to the Regulator. Security deposits held by the Regulator in cash form are not interest bearing.

5.5 Non-Compliance

Permit holders who fail to submit required security deposits within the allotted timeframe may be in noncompliance with Section 30 of ERAA. 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 application or assessment, additional compliance actions are taken against the permit holder, which may result in the cancellation of permits or orders to cease operations.

Chapter 6: Dispute Process

6.1 Dispute Process

Permit holders may dispute a required security deposit by submitting a dispute request to the Regulator. A dispute request is based on the permit holder's specific inventory and must support revised liability calculations. 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 Regulator they are qualified to perform the 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 Regulator to understand the dispute, arguments and requested remedies.

Dispute requests can be made to:

Liability.Management@bc-er.ca

or

BC Energy Regulator
Liability Management

2950 Jutland Rd, Victoria, BC V8T 5K2

6.2 Site-Specific Liability Assessments

At the request of the Regulator, a permit holder may be required to complete a Site-Specific Liability Assessment for one or more permits to be used in 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 Regulator that they are qualified to complete the assessment. In preparing the Site-

Specific Liability Assessment, permit holders may use as reference the Alberta Energy Regulator Directive 001 – Requirements for Site-Specific Liability Assessment in Support of the ERCB's Liability Management Programs to determine costs.

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 Regulator's Oil and Gas Activity 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*	Abandonment 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		

*For vertical wells, the depth used in the model is the recorded Total Depth from the drilling event data. For horizontal wells, the depth used in the model is the point at which the directional survey indicates 80° was reached, or if no survey is available, the depth of the deepest non-abandoned completion event.

Well Assessment Cost Model

Classification - Status	Age	Assessment Liability Cost		
		Plains Area	Montane Area	Northern Area
All Wells - Never Produced/Injected	-	$4,000	$5,500	$7,500
Gas Well - Active/Inactive/Abandoned	Post 2006	$15,000	$17,500	$20,000
	1990-2006	$15,000	$17,500	$20,000
	Pre 1990	$20,000	$22,500	$25,000
Oil or Condensate Well - Active/Inactive/Abandoned	Post 2006	$20,000	$22,500	$25,000
	1990-2006	$20,000	$22,500	$25,000
	Pre 1990	$22,500	$25,000	$27,500
Cancelled Well w/ Surface Disturbance	-	$0	$0	$0
Water Well	-	Exempt		
Shared Pad w/ Well or Facility and Same Operator Discount	-	Reduce 80%		
Additional Contaminated Media	-	Site Specific Cost		

Well Remediation Cost Model

Classification - Status	Age	Remediation Liability Cost		
		Plains Area	Montane Area	Northern Area
All Wells - Never Produced/Injected	-	$0	$0	$0
Gas Well - Active/Inactive/Abandoned	Post 2006	$0	$0	$0
	1990-2006	$11,500	$16,000	$28,000
	Pre 1990	$34,500	$39,500	$54,000

Oil or Condensate Well - Active/Inactive/Abandoned	Post 2006	$0	$0	$0
	1990-2006	$14,500	$21,000	$33,500
	Pre 1990	$84,000	$98,500	$120,500
Cancelled Well w/ Surface Disturbance	-	$0	$0	$0
Water Well	-	Exempt		
Shared Pad w/ Well or Facility and Same Operator Discount	-	Reduce 50%		
Additional Contaminated Media	-	Site Specific Cost		

Well Reclamation Cost Model

Classification - Status	Age	Reclamation Liability Cost		
		Plains Area	Montane Area	Northern Area
All Wells - Never Produced/Injected	-	$30,000	$40,000	$50,000
Gas Well - Active/Inactive/Abandoned	Post 2006	$30,000	$40,000	$50,000
	1990-2006	$30,000	$40,000	$50,000
	Pre 1990	$40,000	$50,000	$60,000
Oil or Condensate Well - Active/Inactive/Abandoned	Post 2006	$30,000	$40,000	$50,000
	1990-2006	$30,000	$40,000	$50,000
	Pre 1990	$40,000	$50,000	$60,000
Cancelled Well w/ Surface Disturbance	-	$10,000	$12,000	$15,000
Water Well	-	Exempt		
Shared Pad w/ Well or Facility and Same Operator Discount	-	Reduce 80%		
Additional Contaminated Media	-	Site Specific Cost		

Facility Cost Model

Facility Type	Design	Abandonment Liability Cost		
		Plains Area	Montane Area	Northern Area
Gas Processing Facility (Plant Designation)	0 – 999 e^3m^3/d	$159,400	$175,300	$192,900
	1000 – 2999 e^3m^3/d	$307,600	$338,400	$373,200
	3000 – 4999 e^3m^3/d	$413,800	$455,200	$500,700
	5000 – 9999 e^3m^3/d	$527,000	$579,700	$638,700
	>10000 e^3m^3/d	Site-Specific Cost		
Gas Dehydration Facility	0 – 299 e^3m^3/d	$43,800	$48,200	$53,000
	300 – 1499 e^3m^3/d	$109,600	$120,500	$132,500
	>1500 e^3m^3/d	$197,200	$217,000	$238,700
Compressor Stations	0 – 599 KW	$38,500	$42,400	$46,600
	600 – 2999 KW	$93,900	$103,300	$113,600
	>3000 KW	$174,000	$191,400	$210,500
Battery Sites	0 – 49 m^3/d	$40,900	$45,000	$49,500
	50 – 499 m^3/d	$112,700	$124,000	$136,400
	500 – 1500 m^3/d	$201,900	$222,100	$244,300
	>1500 m^3/d	$291,800	$321,000	$353,100
Battery or Disposal Station w/ Separation, Compression, Injection, and/or Disposal Equipment	0 – 49 m^3/d	$59,400	$65,300	$71,900
	50 – 499 m^3/d	$131,200	$144,300	$158,800
	500 – 1500 m^3/d	$245,400	$269,900	$296,900
	>1500 m^3/d	$335,700	$369,300	$406,200
Satellite Batteries	0 – 99 m^3/d	$41,000	$45,100	$49,600
	>100 m^3/d	$61,500	$67,600	$74,400
Other Stations	-	$33,000	$36,300	$39,900
H2S Premium (>1%)	-	Add 10%		
Legacy Premium (Pre 1990)	-	Add 20%		

In reference to the above facility types:

Battery Sites w/ Separation etc. include facilities classified as Water Disposal Stations.
Other Stations – Include injection stations, water hubs, shared facilities, tank terminals and pump stations. KW power is equal to total of all compressors.

Assessment

Facility Type	Design	Assessment Liability Cost		
		Plains Area	Montane Area	Northern Area
Gas Processing Facility (Plant Designation)	0 – 999 e^3m^3/d	$20,000	$22,500	$25,000
	1000 – 2999 e^3m^3/d	$30,000	$32,500	$35,000
	3000 – 4999 e^3m^3/d	$50,000	$55,000	$60,000
	5000 – 9999 e^3m^3/d	$100,000	$110,000	$120,000
	>10000 e^3m^3/d	Site Specific Cost		
Gas Dehydration Facility	0 – 299 e^3m^3/d	$10,000	$12,500	$15,000
	300 – 1499 e^3m^3/d	$25,000	$27,500	$30,000
	>1500 e^3m^3/d	$35,000	$37,500	$40,000
Compressor Stations	0 – 599 KW	$7,500	$10,000	$12,500
	600 – 2999 KW	$25,000	$27,500	$30,000
	>3000 KW	$30,000	$32,500	$35,000
Battery Sites	0 – 49 m^3/d	$7,500	$10,000	$12,500
	50 – 499 m^3/d	$10,000	$12,500	$15,000
	500 – 1500 m^3/d	$12,500	$15,000	$17,500
	>1500 m^3/d	$15,000	$17,500	$20,000
Battery or Disposal Station w/ Separation, Compression, Injection, and/or Disposal Equipment	0 – 49 m^3/d	$10,000	$12,500	$15,000
	50 – 499 m^3/d	$15,000	$17,500	$20,000
	500 – 1500 m^3/d	$20,000	$22,500	$25,000
	>1500 m^3/d	$35,000	$37,500	$40,000
Satellite Batteries	0 – 99 m^3/d	$10,000	$12,500	$15,000
	>100 m^3/d	$15,000	$17,500	$20,000
Other Stations	-	$10,000	$12,500	$15,000
Legacy Premium (Pre 1990)	-	Add 50%		

Shared Pad w/ Well or Facility and Same Operator Discount	-	Reduce 80%

Remediation

Facility Type	Design	Remediation Liability Cost		
		Plains Area	Montane Area	Northern Area
Gas Processing Facility (Plant Designation)	0 – 999 e^3m^3/d	$297,000	$319,700	$345,700
	1000 – 2999 e^3m^3/d	$492,400	$534,600	$582,100
	3000 – 4999 e^3m^3/d	$662,300	$721,500	$787,700
	5000 – 9999 e^3m^3/d	$1,073,700	$1,174,100	$1,285,500
	>10000 e^3m^3/d	Site Specific Cost		
Gas Dehydration Facility	0 – 299 e^3m^3/d	$47,300	$48,500	$50,400
	300 – 1499 e^3m^3/d	$150,200	$158,200	$168,000
	>1500 e^3m^3/d	$268,100	$287,900	$310,700
Compressor Stations	0 – 599 KW	$18,600	$22,400	$26,700
	600 – 2999 KW	$100,500	$103,500	$107,900
	>3000 KW	$195,000	$207,500	$222,300
Battery Sites	0 – 49 m^3/d	$49,900	$50,900	$52,600
	50 – 499 m^3/d	$146,300	$153,900	$163,300
	500 – 1500 m^3/d	$245,100	$262,600	$282,900
	>1500 m^3/d	$333,600	$359,900	$390,000
Battery or Disposal Station w/ Separation, Compression, Injection, and/or Disposal Equipment	0 – 49 m^3/d	$81,900	$83,100	$85,400
	50 – 499 m^3/d	$173,000	$183,300	$195,600
	500 – 1500 m^3/d	$295,600	$318,200	$344,000
	>1500 m^3/d	$384,100	$415,500	$451,100
Satellite Batteries	0 – 99 m^3/d	$40,800	$42,500	$45,000
	>100 m^3/d	$82,500	$83,700	$86,200
Other Stations	-	$33,500	$35,900	$39,000
Legacy Premium (Pre 1990)	-	Add 50%		

Modern Facility Discount (Post 2006)	-	Reduce 50%
Shared Pad w/ Well or Facility and Same Operator Discount	-	Reduce 50% (25% for Post-2006 Facility)

Reclamation

Facility Type	Design	Reclamation Liability Cost		
		Plains Area	Montane Area	Northern Area
Gas Processing Facility (Plant Designation)	0 – 999 e^3m^3/d	$30,000	$40,000	$50,000
	1000 – 2999 e^3m^3/d	$40,000	$50,000	$60,000
	3000 – 4999 e^3m^3/d	$100,000	$150,000	$200,000
	5000 – 9999 e^3m^3/d	$270,000	$300,000	$350,000
	>10000 e^3m^3/d	Site Specific Cost		
Gas Dehydration Facility	0 – 299 e^3m^3/d	$30,000	$40,000	$50,000
	300 – 1499 e^3m^3/d	$40,000	$50,000	$60,000
	>1500 e^3m^3/d	$70,000	$100,000	$150,000
Compressor Stations	0 – 599 KW	$30,000	$40,000	$50,000
	600 – 2999 KW	$40,000	$50,000	$60,000
	>3000 KW	$70,000	$100,000	$150,000
Battery Sites	0 – 49 m^3/d	$30,000	$40,000	$50,000
	50 – 499 m^3/d	$30,000	$40,000	$50,000
	500 – 1500 m^3/d	$40,000	$50,000	$60,000
	>1500 m^3/d	$70,000	$100,000	$150,000
Battery or Disposal Station w/ Separation, Compression, Injection, and/or Disposal Equipment	0 – 49 m^3/d	$30,000	$40,000	$50,000
	50 – 499 m^3/d	$30,000	$40,000	$50,000
	500 – 1500 m^3/d	$40,000	$50,000	$60,000
	>1500 m^3/d	$70,000	$100,000	$150,000
Satellite Batteries	0 – 99 m^3/d	$30,000	$40,000	$50,000
	>100 m^3/d	$30,000	$40,000	$50,000
Other Stations	-	$30,000	$40,000	$50,000

Legacy Premium (Pre 1990)	-	Add 50%
Shared Pad w/ Well or Facility and Same Operator Discount	-	Reduce 80%

Pipeline Cost Model

Classification		Deactivation per Kilometre (Km)			Abandonment		
Code	**Description**	**Plains**	**Montane**	**Northern**	**Plains**	**Montane**	**Northern**
G1	**Gas Small < 323.9 OD (mm)**	$4,000	$4,600	$4,600	$10,000	$10,000	$10,000
G2	**Gas Medium >= 323.9 and < 660.0 OD (mm)**	$6,000	$6,900	$6,900	$10,000	$10,000	$10,000
G3	**Gas Large >= 660.0 OD (mm)**	$12,000	$13,800	$13,800	$10,000	$10,000	$10,000
L1	**Liquids Small < 323.9 OD (mm)**	$5,000	$5,750	$5,750	$10,000	$10,000	$10,000
L2	**Liquids Medium >= 323.9 and < 660.0 OD (mm)**	$11,000	$12,650	$12,650	$10,000	$10,000	$10,000
L3	**Liquids Large >= 660.0 OD (mm)**	$15,000	$17,250	$17,250	$10,000	$10,000	$10,000