Certificates of Financial Responsibility Under HB 4100:

Evidence and Options for Oregon's Requirements

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Executive Summary

Many of Oregon's largest fuel terminals sit in northwest Portland at the Critical Energy Infrastructure (CEI) Hub, on soil that can turn unstable in strong shaking. A major Cascadia earthquake could damage many tanks at once while damaged roads and lost water supply slow the response. House Bill 4100 (2026) requires each terminal to hold a certificate from the Oregon Department of Environmental Quality (DEQ) proving it can pay a set amount, up to $300 million, toward the public cost of a spill, including cleanup, fire damage, and harm to fish, wildlife, and habitat. This report reviews the evidence and recommends how to set the amount for the first certificates, due March 31, 2027.

2.3–4.6 million	**12 of 13**	**$18.5 billion**	**$100 million+**
Barrels of fuel that could spill from the Hub in a major Cascadia earthquake	Terminals that would owe the full $300 million under our recommendation	Total owed before the $300 million cap, compared with $3.85 billion after it	Multnomah County's estimate of its first costs, with no money set aside

Sources: ECONorthwest (2022); Multnomah County Board of Commissioners (2026); Table 11 of this report.

Findings:

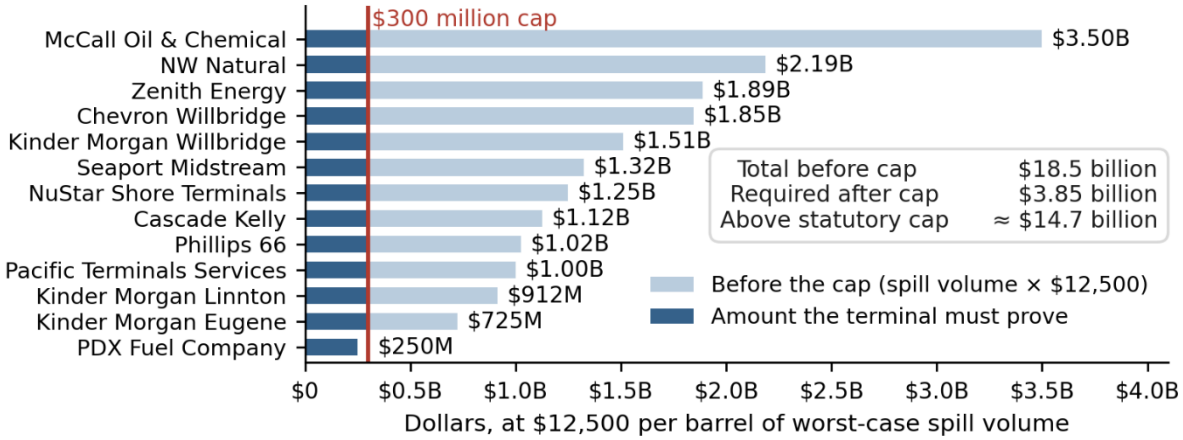
A simple calculation fits the evidence. The six statutory criteria do not support separate numerical weights. They instead inform two inputs—a spill quantity (*Q*) and a cost per barrel (*U*)—with commercial availability testing whether the resulting amount can be demonstrated. The initial calculation is therefore $Q \times U$, subject to the $300 million maximum.

The maximum determines most requirements. At $12,500 per barrel, twelve of the thirteen terminals with a WCS reported to DEQ reach $300 million (Figure ES-1). Even California's lower rates would change the requirement for only one terminal. Across reporting terminals, the uncapped calculation is about $18.5 billion, compared with $3.85 billion after applying the maximum. The uncapped total indicates the gap between the calculation and the cap, not the losses from one earthquake.

Available evidence does not support a lower unit cost. Estimates below $3,000 per barrel generally cover only part of the liability or small spills. Natural resource damages alone average about $8,350 per barrel, while other relevant cost estimates exceed $12,500. The $12,500 rate is therefore a common initial benchmark, not an Oregon-specific cost estimate.

It is recommended that facility-specific differentiation begin with spill quantity. *Q* represents physical exposure that can be evaluated through engineering evidence; *U* represents a common regulatory estimate of consequences. Operators could support a different *Q* through third-party engineering analysis subject to DEQ review. *U* remains a common benchmark until stronger evidence supports differentiation. It is also recommended that accepted financial mechanisms remain accessible after earthquake-triggered and correlated losses.

Figure ES-1: What Each Terminal Would Owe at $12,500 per Barrel, Before and After the Cap



Note: Uses each terminal's reported worst-case spill volume. Three terminals that have not reported one are not shown.

Table ES-1: Recommendations for the First Certificates

Topic	Recommendation
Calculation	Verified Worst-case Spill volume × $12,500/bbl, up to $300 million.
Quantity	Worst-case spill volume, not less than the largest in-service tank.
Facility-specific Adjustment	Adjust Q through DEQ-reviewed engineering evidence.
Unit Cost	Keep $12,500/bbl common initially.
Mechanisms	Verify exclusions, shared limits, and access to funds.
Reporting	Record capped and uncapped amounts.
Nonpetroleum Materials	Use benchmark provisionally; develop material-specific methods later.
Future Review	Revisit Q, U, maximum, and residual funding as evidence develops.

1. Context and Problem Definition

1A. Overview of HB 4100

In 2026, the Oregon Legislative Assembly passed House Bill 4100, which requires owners or operators of bulk oils or liquid fuels terminals to acquire and maintain a certificate of financial responsibility (COFR) issued by the Oregon Department of Environmental Quality (DEQ). The bill directs the Environmental Quality Commission (EQC) to adopt rules establishing reasonable minimum amounts of financial assurance for spill-related liabilities (HB 4100 2026). It builds on Senate Bill 1567 (2022), which established the Fuel Tank Seismic Stability (FTSS) Program and required the same terminals to submit seismic vulnerability assessments.

Where SB 1567 addressed whether terminals would withstand a Cascadia Subduction Zone earthquake, HB 4100 addresses whether their owners can pay the public costs of a release.

1B. Objectives of this Report

This report draws on statutes and rules, agency rulemaking files, incident cost documentation, published spill-cost research, and interviews with program staff in California and Alaska to assemble evidence for each criterion in §4(2)(a) of HB 4100 and translates it into a framework for calculating the financial assurance a terminal must demonstrate to obtain a COFR. It is organized around the following questions:

- What does a COFR guarantee, and how do its components inform the amount required?
- What do historical incidents and projections imply about the public cost of a release in Oregon?
- How do comparable jurisdictions calculate their requirements, and on what basis?
- How do environmental sensitivity and commercial market capacity bear on the amount?
- What calculation can the EQC adopt in 2027, and how can it be refined as Oregon evidence develops?

2. On Certificates of Financial Responsibility (COFRs)

2A. The Purpose and Function of COFRs

A certificate of financial responsibility is an administrative determination that a regulated entity has demonstrated access to a specified amount of financial resources. It is not itself a fund, insurance policy, or guarantee, and the certified amount does not limit the liability a terminal may incur after a spill. Under HB 4100 §3(1), the COFR confirms that a terminal has the financial ability to cover potential spill-related liabilities. That ability may be demonstrated through insurance or self-insurance, surety bonds, letters of credit, trusts, or other evidence accepted by the EQC (§3(2)).

A COFR serves two related functions. First, maintaining financial responsibility is a condition of continued compliance. California and Alaska, for example, can restrict the operations of facilities that fail to maintain the required financial responsibility, and HB 4100 likewise directs the EQC to establish standards for restricting or suspending noncompliant terminals (§4(2)(h)(B); 18 AAC 75.290; OSPR staff, interview, June 30, 2026). Second, the financial assurance mechanisms behind the certificate provide a source of funds if the responsible party does not meet its obligations. Depending on the mechanism, this may allow the agency to draw on or activate a guarantee, letter of credit, surety, trust, or other instrument to make funds available for covered costs.

The effectiveness of a COFR depends on more than just the amount stated on the certificate. It also depends on what liabilities are covered and whether the underlying financial instrument can be accessed when payment is needed. California and Alaska, for example, use specific requirements for the financial instruments supporting their certificates. These provisions address issues such as deductibles, cancellation, exclusions, and access to funds. These provisions underscore that the amount stated on a COFR and the amount actually accessible when a claim arises are not necessarily the same. Comparable West Coast programs generally calculate the required amount using a volume measure and per-barrel rate, subject to a maximum. Chapter 4 examines these approaches in detail.

2B. The Statutory Framework and Scope of HB 4100

HB 4100 directs the EQC to establish reasonable minimum amounts of financial assurance. The purpose of this report is to help DEQ determine how those minimums could be calculated from the criteria in §4(2)(a). The criteria address three questions:

- **How much material could be released?**
- **What could that release cost?**

- **Can the resulting amount be demonstrated through available financial assurance mechanisms?**

The criteria governing the amount appear in §4(2)(a):

> (2) Rules adopted by the [EQC] must:
> (a) Establish reasonable minimum amounts of financial assurance based on an evaluation of:
>
> > (A) The type, size and operational risk of bulk oils or liquid fuels terminals;
> > (B) The maximum volume of oil, liquid fuel or hazardous materials handled by bulk oils or liquid fuels terminals;
> > (C) Historical spill or release response costs and projected cleanup expenses in the areas where bulk oils or liquid fuels terminals operate;
> > (D) The environmental sensitivity of the areas where bulk oils or liquid fuels terminals operate;
> > (E) Commercially available financial assurance mechanisms, including maximum coverages offered; and
> > (F) Financial assurance requirements in other jurisdictions

For the report, criteria (A) and (B) inform the quantity of material at risk. Criteria (C), (D), and (F) inform the cost associated with that release. Criterion (E) addresses whether the resulting amount can be demonstrated in practice. Chapter 3 examines historical and projected costs; Chapter 4 addresses criterion (F) by comparing other jurisdictions; Chapter 5 considers environmental sensitivity; Chapter 6 addresses commercial availability and mechanism reliability; and Chapter 7 presents a proposed approach to the reasonable minimum.

Scope of the Financial Assurance Requirement

Two definitions set the scope of the financial assurance requirement. Section 3(4) defines a spill or release to include discharges to air, land, or water, so a cost basis limited to water spills would capture only part of the statutory scope. Section 3(5) defines spill-related liability to include costs and damages incurred by the State, tribes, cities, and counties, including response and cleanup, fire damage, and natural resource damage assessment and restoration. This report therefore focuses on those public-sector liabilities in estimating a reasonable minimum but does not assume that third-party claims are categorically excluded.

Other Provisions Affecting Reasonable Minimum Financial Assurance Requirements

Several provisions outside §4(2)(a) also shape the calculation:

- **Combined mechanisms.** A terminal may use more than one form of financial assurance. This means the requirement is not limited to the amount available from a single insurance policy.
- **Self-insurance.** A terminal that relies on its own financial strength must meet standards for solvency, creditworthiness, and ongoing financial reporting. HB 4100 also requires these standards to be at least as protective as those used in comparable jurisdictions.
- **Federal consistency.** Oregon's rules must be consistent with federal law while still reflecting Oregon-specific conditions. The federal onshore-facility liability limit is one point of comparison discussed in Chapter 4.
- **Periodic updates.** The EQC must revisit the minimum amounts over time to account for inflation, industry changes, emerging risks, and lessons from spill response. Alaska provides one example by adjusting its amounts every three years for inflation.
- **Local requirements.** Local governments generally cannot impose separate financial assurance requirements beyond the state rule. This makes the state requirement especially important, although other sources of spill-response and recovery funding may still be available after an incident.

Public-Sector Costs Relevant to the Minimum Amount

Section 3(5) identifies costs and damages incurred by the State, tribes, cities, and counties. The purpose of this section is to illustrate the types of public costs the financial assurance requirement may need to cover. At the CEI Hub, these costs could include emergency response, cleanup, infrastructure repair and decontamination, natural resource damage assessment, and restoration. After a Cascadia earthquake, damaged transportation routes, prolonged loss of municipal water, competing demands on firefighters, and delays in bringing outside spill-response resources into the Hub could make response slower and more difficult (Hanst and Wang 2026).

Multnomah County has estimated that its initial costs from a major Hub release could exceed $100 million and testified that it does not maintain a reserve of that scale for immediate response (Multnomah County Board of Commissioners 2026). Federally recognized tribes also hold trustee interests in natural resources of the lower Willamette and Columbia rivers. Those interests are relevant because §3(5) expressly includes natural resource damage assessment and restoration among the covered liabilities (ECONorthwest 2022).

3. Historical Costs and Projected Cleanup Expenses for Oregon

Criterion (C) requires an evaluation of historical spill or release response costs and projected cleanup expenses in the areas where terminals operate. Projected costs for the CEI Hub are well developed. Historical costs are thinner, because no event of comparable scale has occurred in Oregon.

3A. The Critical Energy Infrastructure Hub in Portland

The CEI Hub is a roughly six-mile concentration of bulk fuel terminals along the lower Willamette River in northwest Portland, bounded on the west by Forest Park. It holds the large majority of Oregon's liquid fuel supply and effectively all of its jet fuel. A 2019 inventory identified at least 362 in-service tanks across nine operating companies with a combined capacity of 8.64 million barrels, and found that the roughly 40 percent of tanks measuring 25 feet or more in diameter hold over 95 percent of that volume (Dusicka and Norton 2019). Most were built before the 1960s, before regional seismicity was understood or reflected in design standards. The 2022 consequence assessment counted 630 tanks, of which 415 are active, with a maximum active capacity of 332.7 million gallons. About 65 percent of that capacity holds light oil such as gasoline and diesel, and at an average fill of 67 percent the Hub would contain 233.5 million gallons (ECONorthwest 2022).

The soils beneath the Hub are loose to medium-dense silty sands below the water table and are susceptible to liquefaction. Permanent ground deformation from liquefaction and lateral spreading is expected to be very high at every tank location (Dusicka and Norton 2019). Aged tanks on unstable soil make the design scenario for Oregon a simultaneous failure across many tanks and terminals, not a single-tank event.

3B. Historical Incidents Relevant to Oregon

Oregon has a history of spills, but none approaches the scale or complexity of the scenarios modeled for the CEI Hub. The largest contaminated-site figure associated with the same receiving reach is the Portland Harbor Superfund remedy. That figure is an estimated cost of addressing legacy sediment contamination. It is not a realized response expenditure, and it is not attributable to any terminal covered by HB 4100.

Oregon incidents therefore serve two purposes here. They document the scale and composition of response costs under local conditions, and comparison among them identifies the factors that drive cost: release volume, receiving environment, product characteristics, access, fire, infrastructure involvement, and the duration of contamination.

Takeaways from Selected Cases

Table 1 lists incidents in Oregon that prior studies commonly cite. They span the lower Columbia River, the Columbia River Gorge, the coast, and the Portland metropolitan area, and they include vessel groundings, a rail derailment, a highway tanker spill, a hazardous material release, and a legacy terminal contamination site.

Table 1: Selected Cases Relevant to Oregon's Context

Incident	Relevance	Available Cost Evidence?
SS Mobiloil Grounding, Columbia River (1984)	Complexity of response	~$9.8M
M/V New Carissa, Coos Bay (1999)	Natural resource damages	~ $53.5M
Mosier derailment, Columbia Gorge (2016)	Cascading public costs	Not yet identified
Lindsey Lake, Hood River (2019)	Environmental sensitivity	~$4.4M
Former Time Oil Terminal, Portland (2023)	Long-term Liability	Not yet established
Hayden Island acid release, Portland (2026)	Non-oil response	Not yet established

Note: Cost evidence for incidents have been adjusted for inflation and are reported in 2026 dollars where available.

Source: Park (1985); Pilkey-Jarvis and Irwin (2017); ECONorthwest (2022); DEQ (2026)

None is a direct analogue to a Cascadia-induced release from several terminals at once, but together they identify the cost drivers discussed below.

Economies of scale in spill response depend on response capacity: The Lindsey Lake spill cost approximately $42,300 per barrel and the MobilOil grounding approximately $2,400, both in 2026 dollars. The contrast is consistent with the tendency for per-barrel costs to fall as volume rises, but that tendency depends on the ability to mobilize personnel, equipment, logistics, and incident command (Catalyst Environmental Solutions et al. 2019). A Cascadia event would disrupt transportation, water, power, communications, and the availability of first responders, and per-barrel costs may then stop declining with volume (ECONorthwest 2022; Hanst and Wang 2026).

The receiving environment materially affects response costs: Lindsey Lake was a small release with unusually high costs. Approximately 105 barrels of diesel generated about $3.4 million in reported response costs (ECONorthwest 2022), whereas the California operator survey reports a median of $343 per barrel for small inland releases that do not reach flowing water (Catalyst Environmental Solutions et al. 2019). The Lindsey Lake release reached salmon spawning habitat connected to the Columbia River, which indicates that location and receiving environment determine cost alongside volume and product.

Reported release volumes are uncertain: In the MobilOil incident, the responsible party could not state the quantity released or recovered with confidence, because different oil grades and

oil-water mixtures were combined and early recovery estimates relied on calculated yields (Park 1985). At Mosier, part of the released crude oil was recovered, part was removed with contaminated soil, and the remainder was estimated to have burned or volatilized (Pilkey-Jarvis and Irwin 2017). A reported spill volume is therefore an estimate, and per-barrel figures derived from it inherit that uncertainty.

Observed cleanup costs understate public costs: The Mosier derailment required fire response, evacuation, air monitoring, repair of transportation infrastructure, restoration of disrupted water and wastewater service, and longer-term groundwater treatment in addition to containment and remediation (Franklin 2016). It also required public outreach and coordination among agencies in two states. Per-barrel cleanup estimates seldom capture costs of this kind.

Liability can outlast the operator: At the former Time Oil Northwest Terminal, chronic contamination remained after the operator entered bankruptcy. Several attempts to sell the property failed before DEQ negotiated a prospective purchaser agreement in 2021, under which the buyer performed substantial remediation in exchange for protection from liability for legacy contamination (Oregon Department of Environmental Quality 2026). Cleanup thus depended on DEQ's ability to find a willing purchaser and structure a viable transaction, not on the solvency of the responsible operator. Where remediation costs exceed the value a purchaser can recover from reuse, no private party may be available to assume the work.

3C. Cost Evidence Beyond Oregon

Oregon's incidents establish local context but include few releases at volumes comparable to a terminal's worst-case spill (WCS) volume, the largest foreseeable spill that each terminal identifies in its Oil Spill Contingency Plan. The WCS is a facility-level planning figure and is distinct from the Hub-wide Cascadia release modeled in the consequence assessment studies examined later in this chapter. Releases elsewhere in the United States supply observations in the thousands to tens of thousands of barrels. They are not geographic analogues for the CEI Hub. Table 2 presents cases with comparable volumes, failure mechanisms, or cost-recovery structures.

Table 2: Selected Cases from Outside Oregon

Incident	Approximate Release	Observed Cost Evidence	Relevance	Caveat
Cosco Busan, San Francisco Bay (2007)	~ 1,276 bbl	~$72.6M response costs; $36.8M NRD component of a $44.4M civil settlement; $8.4M third-party claims and ~$12.4M fines.	Contemporary cost response-cost on heavily used shoreline	Marine vessel spill; observed costs combine natural resource damages, third-party claims, and fines.
Refugio pipeline, Santa Barbara County (2015)	~2,500 bbl	$64.5M response and cleanup costs and $22.3M natural resource damages, and $10M NRDA assessment cost reimbursement.	Small-volume high-cost shoreline release, demonstrates role of environmental sensitivity and response complexity	Pipeline, not terminal release; Pacific shoreline differs from Willamette.
Enbridge Line 6B, Kalamazoo River (2010)	~ 20,082 bbl	Cleanup costs >$767M; later reported at $1.2B in total spill-related costs.	Closest large freshwater analog to Oregon's context.	$1.2B figure combines removal costs and damages
Murphy Oil, Meraux, Louisiana (2005)	~ 24,000 bbl	$51.86M already spent on remediation, $20M in additional remediation within a broader $330M class settlement and a $55M property-buyout program.	Close structural analog; natural disaster (Hurricane Katrina) causing failure of above ground crude-oil storage tank.	Much of the settlement comprises private property and compensation outside of HB 4100's assured-liability scope
CITGO Lake Charles, Louisiana (2006)	~ 54,000 bbl	$19.69M Natural Resource Damage settlement, including cost of restoration	Refinery/tank release into river-estuary system within Oregon's volume range	Recorded cost evidence is Natural Resource Damage rather than cleanup and containment costs
Exxon Valdez, Prince William Sound (1989)	~ 257,000 bbl	$4.2B in response and containment	Upper end of Oregon's WCD range and provides observable catastrophic-response benchmark	Marine vessel spill, not a terminal release.

The Enbridge Line 6B release is the closest comparison for a large freshwater spill. It discharged diluted bitumen into wetlands, Talmadge Creek, and the Kalamazoo River at a volume near the lower end of Oregon terminals' reported worst-case discharge values. The Coast Guard reports approximately $1.8 billion in removal costs and damages in 2025 dollars (US Coast Guard 2026). Because that figure combines removal costs with private damages, it is broader than the public liability HB 4100 assures.

The Murphy Oil release is the closest structural comparison. Hurricane Katrina damaged an aboveground crude oil storage tank at the Meraux refinery and released approximately one million gallons onto the facility and an adjacent neighborhood of roughly 1,800 homes (Government Accountability Office 2007). The class settlement identified $51.86 million already spent on remediation and at least $20 million more for remediation outside the buyout zone, within a much larger settlement that also compensated private losses (*Turner v. Murphy Oil USA* 2007). Participants in a recent National Academies workshop series described the incident as an example of local mobilization, in which local governments and residents familiar with the land and waters led the development of cleanup strategies and long-term recovery (Cohen et al. 2025, 151).

The CITGO Lake Charles release is well documented. At least 54,000 barrels of waste oil and an undetermined volume of oily wastewater escaped containment and reached the Calcasieu River

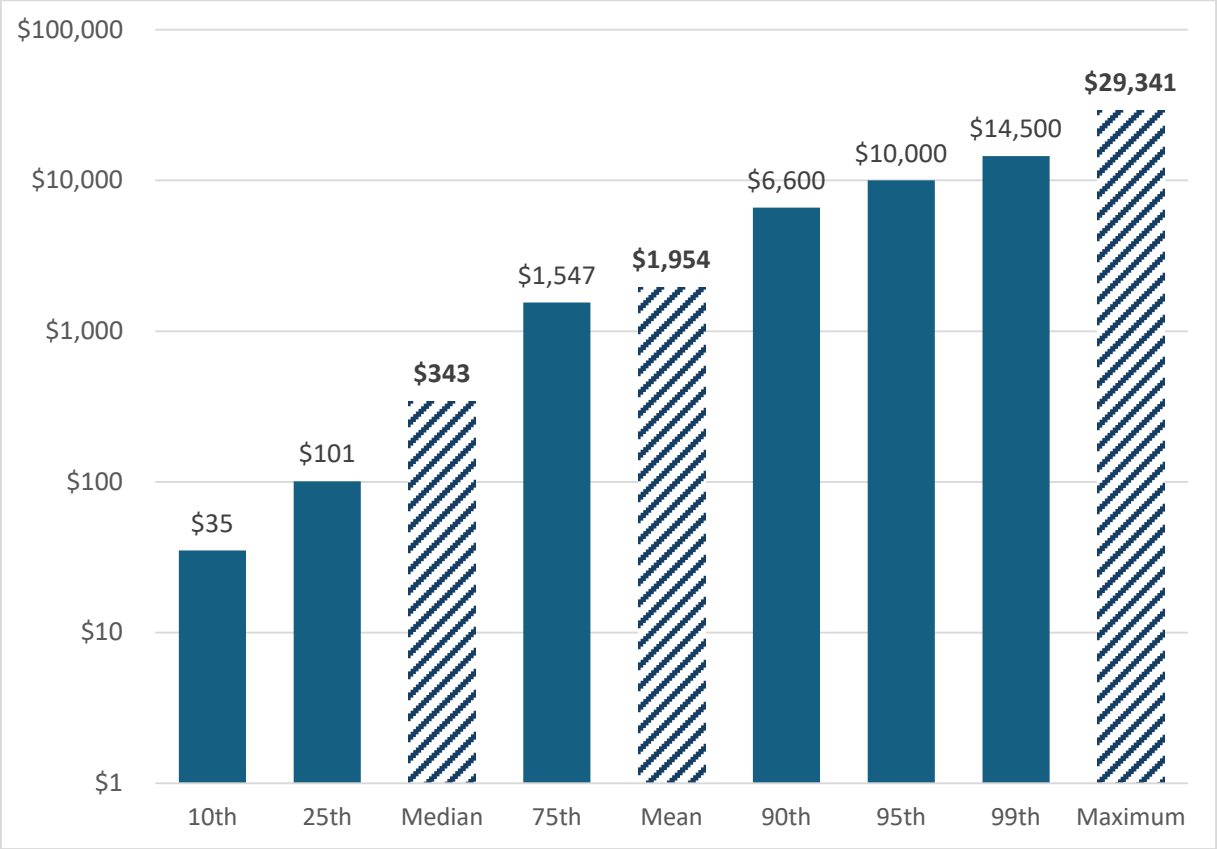
system, oiling about 150 miles of shoreline. The natural resource damage claim was resolved in 2021 for $19.69 million, of which approximately $19.16 million funded restoration and $528,000 reimbursed assessment costs (NOAA 2021). Cleanup costs are reported at approximately $65 million ($115 million including combined fines and settlements), and the per-barrel figure depends on whether the denominator is the waste oil alone or all liquid handled (Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management 2016).

The Exxon Valdez release, at 261,905 barrels, sits at the top of the range of worst-case discharges reported in Oregon, the largest of which is 280,000 barrels. Response costs were roughly $16,000 per barrel (*USA v. CITGO Petroleum Corporation (5th Cir. 2018)* 2018)). The release nonetheless represented only about 20 percent of the vessel's cargo. The California cost study observes that no fully loaded tanker has released its entire cargo in United States waters, so the largest spill for which cost evidence exists was itself a partial release (Catalyst Environmental Solutions et al. 2019).

Small Spills and the National Distribution of Incident Costs

At the lower end of the volume range, the operator survey underlying the California cost study collected costs for 133 spills at inland production facilities between 2015 and 2018, all under 100 barrels and none reaching flowing water. It is the only per-barrel evidence available for releases that do not reach water. The study finds that unit costs generally fall as volume rises, but only where response infrastructure and management systems are already in place and well resourced (Catalyst Environmental Solutions et al. 2019).

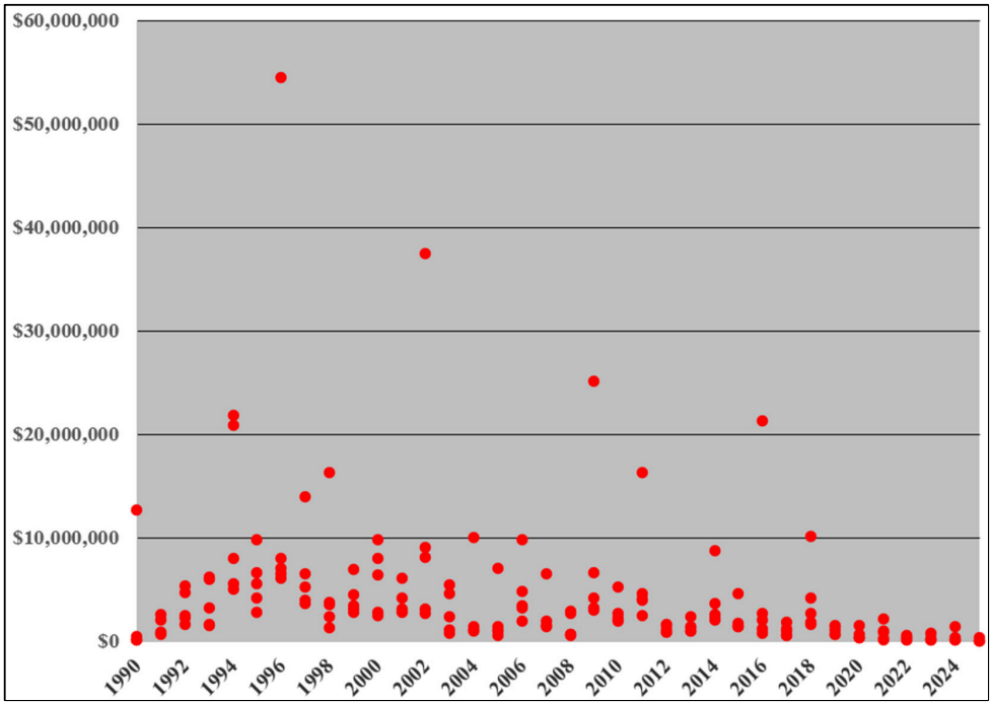
Figure 1: Response Cost Per Barrel from California Oil Spill Response Cost Study



Source: Catalyst Environmental Solutions et al. (2019)

The Coast Guard's periodic report to Congress on Oil Pollution Act (OPA) liability limits compiles the cost of every onshore facility incident since the Act took effect (US Coast Guard 2026). An onshore facility's limit of liability is a single per-incident amount covering both removal costs and damages, currently $725,710,800. Two incidents have exceeded it: the 2010 Enbridge Line 6B release, at approximately $1.8 billion, and the 2022 Keystone Pipeline release, at $873.4 million, both in 2025 dollars. None of the other 5,606 onshore facility incidents approaches the limit (Table 3).

Table 3: Total Incident Cost of the Five Most Expensive Onshore Facility Incidents per Year (in 2025 Dollars; Excludes 2010 Enbridge and 2022 Keystone Pipeline Oil Spills)



Source: US Coast Guard (2026)

Most of these incidents were small releases handled by on-site personnel or a small crew without an incident command structure. Incident costs therefore do not form a smooth distribution from routine to catastrophic. For criterion (C), ordinary incidents describe the scale of routine response, while the two outliers show why routine costs cannot establish the cost basis for the low-frequency, high-consequence event HB 4100 addresses.

The Coast Guard's adequacy finding carries the same limitation. The 2026 report states that the National Pollution Funds Center expects the Oil Spill Liability Trust Fund to cover projected non-catastrophic liabilities without further increases to the limits. That finding concerns the federal financing structure for non-catastrophic incidents and does not imply that the limit would cover a catastrophic onshore event.

Earthquake-Induced Releases

None of the cases in Tables 1 and 2 was triggered by an earthquake, and the closest natural-hazard analogue is the hurricane-induced Murphy Oil release. Earthquakes, floods, and lightning trigger roughly 2 to 5 percent of the accidents recorded in industrial accident databases, and storage tanks and pipes are the equipment most often damaged (Krausmann et al. 2017). The European Commission's eNatech database compiles such events, but its records describe

consequences in physical terms and report economic impacts, where present, as narrative (Joint Research Centre 2024). Engineering accounts of the 2003 Tokachi-oki earthquake likewise document sunken floating roofs and two tank fires at a refinery in Tomakomai without reporting their cost (Hatayama 2008).

The best-documented case is the Tüpraş refinery in the 1999 Kocaeli earthquake, where fire destroyed six naphtha tanks and oil reached Izmit Bay. The reported cost of restoration, including oil spill cleanup, was $57.8 million at the time, about half the initial estimate, and insurance covered 95 percent of the loss (Girgin 2011). That figure combines refinery repair with fire and spill response, and no released volume is reported in a form that would support a per-barrel rate. The limitation is general. Published spill costs are seldom broken down by cost type (Catalyst Environmental Solutions et al. 2019), and consequence assessments for an earthquake scenario place earthquake damage in the baseline and count only the costs attributable to the release (ECONorthwest 2022). The available data therefore do not support an earthquake-specific unit cost. They also provide no basis for a discount, since natural resource damage settlements show no relationship to the cause of a spill (Hodgdon and Industrial Economics 2023) and the Natech conditions discussed later in this chapter point toward higher response costs.

3D. Natural Resource Damage Settlement History

Section 3(5)(c) includes natural resource damage assessment and restoration within the assured liability. These costs are separate from response and cleanup. The most systematic evidence is a national compilation of 88 assessed oil spills with settlement data (Hodgdon and Industrial Economics 2023). Its findings relevant to Oregon are as follows:

- Settlement amounts increased with spill volume, but less than proportionally. The fitted relationship, $\ln(\text{settlement}) = 8.88 + 0.50 \times \ln(\text{volume})$, with $R^2 = 0.25$, means that a 1 percent increase in spill volume was associated with roughly a 0.5 percent increase in settlement value. Larger spills therefore tended to have lower natural resource damages per barrel, although spill volume explained only part of the variation in settlements.
- The mean settlement was $198.80 per gallon, or about $8,350 per barrel in 2026 dollars. This covers only natural resource damages and excludes response and cleanup.
- Settlements were higher where protected species were injured, with some of the highest volume-adjusted settlements occurring along the Pacific coast.
- The cause of the spill was not significantly related to settlement value. Spills associated with natural causes were not associated with lower damages. For Oregon, this means the available settlement evidence does not support reducing expected natural resource damages simply because a release is earthquake-triggered.

Settlement amounts do not reflect ecological injury alone. They also depend on what injuries can be documented, how restoration is valued, and how claims are resolved. Establishing conditions before a spill can itself be difficult where ecosystems vary naturally or where injuries appear over time. Participants in the 2025 Gulf-Alaska knowledge exchange identified these baseline conditions and the question of when a resource can be considered recovered as important sources of uncertainty in natural resource damage assessment (Cohen et al. 2025).

3E. Projected Cost Evidence for the CEI Hub

A magnitude 9.0 Cascadia Subduction Zone earthquake is projected to release 94.6 million to 193.7 million gallons from the Hub, or roughly 2.25 million to 4.61 million barrels, which is 28 to 58 percent of active capacity (ECONorthwest 2022). Approximately 57 percent of that volume would remain on the ground and 43 percent could flow into the Willamette River, a release to water of 40.8 million to 82.5 million gallons. Ninety-one percent of active tanks were built before 1993 or are of unknown vintage (ECONorthwest 2022). More than 45,000 people live or work near the Hub (Hanst 2023).

Table 4: ECONorthwest Estimates on Potential Releases and Monetized Costs

Spill Location	Lower Bound	Upper Bound
Ground (gal)	53,882,252	111,183,900
Water (gal)	40,751,753	82,503,352
Total (gal)	**94,634,005**	**193,687,252**
Category of Costs		
Direct Impacts to People ($)	$ 49,000	$ 74,100,000
Impacts to Property ($)	$ 11,800,000	$ 35,400,000
Impacts to Navigation ($)	$ 11,800,000	$ 17,800,000
Impacts to Fisheries	Not Monetized	
Impacts to Recreation	Not Monetized	
Impacts to Human Health ($)	$ 121,000,000	$ 249,000,000
Impacts to Habitats and Species ($)	$ 87,000,000	$ 669,000,000
Cleanup Costs ($)	$ 109,000,000	$ 1,400,000,000
Impacts to Cultural Values	Not Monetized	
Impacts to Fuel Prices ($)	$ 18,800,000	$ 120,800,000
Total Monetized Costs ($)	**$ 359,449,000**	**$ 2,566,100,000**

Source: ECONorthwest (2022)

To estimate response costs, ECONorthwest applied two per-gallon rates to the volume reaching water: $2.67 for large marine spills and $16.60 for marine spills with similar shoreline oiling, or $112 and $697 per barrel (ECONorthwest 2022). The authors expect costs at the Hub to fall

within this range because light fuels predominate and a river requires less booming and staging than open water. The estimate is nonetheless a lower bound for present purposes. It does not monetize fire damage, and it does not account for the wider response effort required in the weeks after a Cascadia event.

ECONorthwest also reports two aggregate figures that are easily conflated. The assessment places an upper bound of $2.6 billion on total monetized costs. It separately reports that the expected value of Oil Pollution Act damages, civil penalties, cleanup costs, and civil claims ranges from $359 million to $2.8 billion (ECONorthwest 2022). The two figures are different aggregates, and neither bounds the other. Table 5 decomposes the $2.8 billion figure and relates each component to §3(5).

Table 5: Distinction between Expected Values and Upper Bound Estimates

Component of the $2.8 billion Expected Value	Expected Value	Upper Bound	Relationship to §3(5)
Cleanup Costs	$ 701,000,000	$ 1,400,000,000	In scope to the extent incurred by the State, tribes, cities, or counties
Damages Covered under the Oil Pollution Act	$ 435,000,000	$ 803,000,000	Partially (§3(5)(c)); also includes privade lost profits and income
Civil Penalties under the Oil Pollution Act	$ 1,600,000,000	$ 8,400,000,000	Outside §3(5); penalties are not costs or damages incurred by listed entities.
Civil Claims for Personal Injury and Wrongful Death	$ 46,000,000	—	Outside §3(5); private third-party claims

Source: ECONorthwest (2022)

Civil penalties make up more than half of the $2.8 billion figure. Penalties are neither costs nor damages incurred by the State, tribes, cities, or counties, so the figure most often cited for the Hub's exposure includes categories that HB 4100 does not assure. The portion plausibly within §3(5) is bounded by the sum of cleanup costs and Oil Pollution Act damages, less the private losses included in those damages.

Spill consequence studies often estimate losses to the local property tax base as a separate category. In an assessment prepared for San Juan County, property values and taxes were the largest damage category in the modeled scenarios (Page et al. 2019). The text of §3(5) does not settle whether lost tax revenue is a damage incurred by a city or county, and the answer affects the liability a certificate is sized to cover.

3F. Summary of Historical and Projected Evidence for Financial Assurance

Table 6 consolidates the per-barrel figures from the preceding sections. Their scopes differ. Section 3(5) limits the assured liability to response and cleanup, fire damage, and natural resource damage assessment and restoration incurred by public entities, and several table figures are broader, chiefly because they include private claims. None prices fire damage.

Table 6: Summary of Selected Cases and Unit Costs

Source and Basis	Per Barrel Cost	Scope
SS MobilOil (1984)	$2,410	Cleanup only
CITGO Lake Charles (2006)	$3,900	Cleanup and damages
Murphy Oil (2005)	$5,000	Cleanup and remediation only
Hodgdon Compilation (mean)	$8,350	Natural Resource Damages only
Exxon Valdez (1989)	$16,000	Response only
M/V New Carissa (1999)	$32,300	Natural Resource Damages only
Refugio (2015)	$33,700	Cleanup and Response Only
Lindsey Lake (2019)	$42,300	Response only
Cosco Busan (2007)	$74,300	Response only
Enbridge Line 6B (2010)	$93,100	Removal costs and damages, inclusive of private claims
San Juan County Scenarios	$1,950 - $13,300	Damages only, excludes response and assessment
Washington NRD compensation schedule	$126 - $12,600	Unquantifiable natural resource damages
ECONorthwest Hub Scenario	$138 - $859	Modeled Scenarios
Catalyst Small Volume Modeled Costs	$8,620 - $13,100	Response and cleanup

Note: All per-barrel estimates have been adjusted to be reflect costs in 2026 dollars.

The costlier cases involved shoreline or freshwater exposure and, in most instances, persistent product, while Murphy Oil was predominantly a land and residential release. Other sources show the same pattern. The California cost study reports modeled per-barrel costs that differ by a factor of four across persistence classes at the same volume (Catalyst Environmental Solutions et al. 2019) and the national settlement compilation finds higher damages where protected species were injured (Hodgdon and Industrial Economics 2023). California and Washington already grade by pathway: Washington in its damage schedule by water type and habitat condition (WAC 173-183-610, -620), and California in its inland rate by whether the water at risk is perennial or ephemeral (14 CCR 791.7). Product persistence and pathway are therefore the two dimensions along which existing evidence can grade a unit cost.

Technological accidents triggered by natural hazards, termed Natech events, involve multiple simultaneous releases, loss of water and power, competition among incidents for scarce response resources, and site conditions that impede responders (Krausmann et al. 2017). The 1999 Izmit earthquake illustrates these difficulties: a refinery with dedicated firefighting capacity and on-site water still sustained a major fire. Similar constraints could be more severe

at the CEI Hub after a Cascadia earthquake, where damaged transportation routes, loss of municipal water, and competing emergencies could delay firefighting and spill response (Hanst and Wang 2026).

Standing response capacity differs as well. Clean Gulf Associates maintains six bases across the Gulf Coast with a two-hour reach objective and pre-positioned equipment, and nothing comparable is dedicated to the lower Willamette. Even so, the response to the 10 major and 134 minor spills that followed Hurricane Katrina, most of them from tank farms, was largely improvised (Cohen et al. 2025). An analysis prepared for the Bureau of Ocean Energy Management reports response costs of roughly $16,000 per barrel for the Exxon Valdez and $5,100 for Deepwater Horizon, against a historical average near $122 for non-catastrophic spills exceeding 32,000 barrels (Industrial Economics and SC&A 2015).

Fire damage is the least developed component of the §3(5) liability. None of the figures in Table 6 price it, and the Hub consequence assessment leaves fire damage unmonetized, including fire in Forest Park (ECONorthwest 2022). Wider literature offers no consensus on what fire costs include or how to value them. A NIST survey of wildfire costs reports an annualized economic burden of $71.1 billion to $347.8 billion and finds that few studies measure economic rather than physical loss (Thomas et al. 2017). The National Fire Protection Association's estimate of the total cost of fire required a new taxonomy of expenditures and losses and departs in method from the association's earlier estimate (Zhuang et al. 2017). Where industrial fire losses are reported, they are typically combined with repair and cleanup. No per-barrel fire component can therefore be transferred from existing studies, and the unit costs in Table 6 understate the §3(5) liability by an unquantified amount.

The largest spill among the selected cases, the Exxon Valdez, is roughly nine to eighteen times smaller than the modeled Hub release, and in no case involves the simultaneous failure of several facilities under a degraded response system. Historical observations therefore benchmark the projected estimates without bounding them. They support grading unit cost by receiving environment and product persistence, which order the observations better than volume does. They do not support lowering the rate on an economy-of-scale rationale; where a calculated amount is large, the statutory maximum already truncates it.

4. Financial Assurance Requirements in Other Jurisdictions

Criterion (F) requires DEQ to consider financial assurance requirements in other jurisdictions. This chapter examines those programs as benchmarks for Oregon's volume basis, unit rate, maximum, and financial mechanisms. Chapters 5 and 6 then return to Oregon-specific environmental sensitivity and commercial availability.

4A. California

California administers financial responsibility through the Office of Spill Prevention and Response (OSPR) in the Department of Fish and Wildlife under 14 CCR 790–798. The program covers tank vessels, nontank vessels of 300 gross tons or more, marine facilities, and inland production facilities, pipelines, and railroads where a spill could affect state waters. Aboveground storage tanks regulated by local Certified Unified Program Agencies are exempt, so at marine terminals the requirement reaches components such as the pipeline between dock and tank farm and not the tanks themselves (OSPR staff, interview, June 30, 2026).

OSPR began operating in 1991 under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act and adopted its financial responsibility regulations on an emergency basis that August. A contemporaneous Alaska legislative memorandum describes a requirement of $1 million to $100 million, calculated as barrels at risk multiplied by $12,500 (Alaska Legislative Research Agency 1994). The $12,500 figure was therefore already in regulation when California retained Mercer Management Consulting in 1993 to study spill costs. OSPR staff date the rate and the $300 million maximum to the rulemakings of that period and could not identify the original calculations (OSPR staff, interview, June 30, 2026).

Mercer estimated spill costs at approximately $450 per gallon, or $18,900 per barrel, and recommended raising the per-barrel figure accordingly (Mercer Management Consulting 1993). California adopted the recommendation only in part. As Table 7 shows, $18,900 applies to nontank vessels, while marine facilities, small tank barges, and mobile transfer units retained $12,500, and inland facilities were later graded at $10,000 and $6,000 by type of receiving water. The entities most similar to Oregon's terminals thus carry the pre-Mercer rate.

Table 7: California's Levels of Financial Responsibility

Regulated Entity	Per-Barrel Cost	Application to COFR Formula
Non-Tank Vessel (1,001 - 7,500 bbl capacity)	$18,900	(Capacity – 1,000bbl) × $5,670 (30% of cargo × $18,900) + $18,900,000 base
Marine facility, offshore platform, marine pipeline	$12,500	× reasonable worst-case spill volume
Small Tank Barge	$12,500	× 30% of total cargo capacity
Mobile Transfer Unit	$12,500	× 30% of maximum cargo capacity
Inland Facility with risk to perennial waters	$10,000	× reasonable worst-case spill volume
Inland Facility with risk to ephemeral or intermittent waters	$6,000	× reasonable worst-case spill volume

Source: Office of Spill Prevention and Response (2026)

Mercer's estimate comprises $150 per gallon for cleanup, $200 for natural resource damages, and $100 for third-party damages (Mercer Management Consulting 1993). The two components within HB 4100 §3(5) total $350 per gallon, or $14,700 per barrel in 1992 dollars and approximately $35,000 in 2026 dollars. They account for 78 percent of the total, and natural resource damages are the largest single component at 44 percent.

California's experience carries two implications for Oregon. The $12,500 rate is a historical regulatory benchmark and not a currently calibrated cost estimate: it predates the state's principal cost study, survived a recommendation to raise it, and has never been indexed. California also addressed heterogeneity through rates differentiated by entity class and receiving environment, not through a single higher rate. Senate Bill 237 now requires OSPR to review its rates and maximums, and a contracted study is due June 30, 2027 (OSPR staff, interview, June 30, 2026).

4B. Washington

Washington regulates financial responsibility for onshore and offshore facilities and covered vessels under chapter 88.40 RCW and chapter 173-187 WAC, administered by the Department of Ecology. Ecology adopted the current rule on June 14, 2024, effective July 15, 2024, implementing Engrossed Second Substitute House Bill 1691 (Washington State Department of Ecology 2024b). The rule distinguishes three classes. Class 1 facilities, which include refineries, marine terminals, offshore facilities, and pipelines, must demonstrate $12,500 per barrel of worst-case spill volume up to $300 million. Class 2 mobile tank units apply the same rate to 30 percent of container contents, and Class 3 small marine terminals apply it to the volume of the largest tank, each up to $5 million (WAC 173-187-110). Neither the rate nor the maximums are indexed. A facility may request an alternative amount based on the response costs and damages of its own reasonable worst-case spill, which Ecology must decide within 65 days after a 30-day

public review (WAC 173-187-120). Operating without compliant financial responsibility carries civil penalties of up to $100,000 per day, criminal liability for knowing violations, and possible suspension or revocation of the certificate after a spill (RCW 88.40.040; RCW 88.40.060; RCW 90.56.300; RCW 90.56.310).

Ecology reconsidered the amount in 2024. It noted that the $12,500 rate and $300 million maximum rested on 1990s dollar values and evaluated an inflation-adjusted alternative of $27,200 per barrel with a $600 million maximum. It declined the increase on grounds of market capacity: commercial pollution insurance for onshore facilities had a practicable upper limit near $200 million, above which facilities must add other mechanisms at substantially greater burden (Posewitz et al. 2024). Ecology did not find that $12,500 reflects contemporary costs.

Responding to a comment proposing $60,153 per barrel on the basis of the Enbridge Line 6B release, Ecology acknowledged that $300 million might not cover a worst-case event. It concluded that a higher requirement could leave several facilities unable to comply and rejected the proposal under the least-burdensome-alternative test of the Administrative Procedure Act (Washington State Department of Ecology 2024b). Consistency with California, which Ecology described as having the highest facility requirements on the West Coast, served as a floor and not as a derivation of the rate (Posewitz et al. 2024).

Washington also maintains a graded natural resource damage schedule. For spills of 1,000 gallons or more, compensation for damages that cannot reasonably be quantified ranges from $3 to $300 per gallon, or $126 to $12,600 per barrel. The amount varies with the toxicity, mechanical injury potential, and persistence of the oil and with the vulnerability of the receiving environment, and it may be reduced for documented containment and rapid recovery (RCW 90.48.366; chapter 173-183 WAC).

4C. Alaska

Alaska requires proof of financial responsibility from operators of oil terminals, pipelines, exploration and production facilities, tank vessels and barges, nontank vessels, and railroad tank cars (AS 46.04.040; AS 46.04.055; 18 AAC 75, art. 2). Terminals with storage capacity below 5,000 barrels of crude oil or 10,000 barrels of noncrude oil are exempt (AS 46.04.050(a); 18 AAC 75.205(a)(1)).

The requirement operates alongside the state’s contingency planning program. Contingency plans are renewed every five years, while proof of financial responsibility must remain continuously effective and is verified annually. Self-insurance approvals expire after one year,

and approvals based on insurance, surety, or a guarantee expire with the underlying instrument (AS 46.04.040(f)–(g); Alaska Department of Environmental Conservation 2024).

For the period beginning October 1, 2023, a crude oil terminal must demonstrate $111.45 million per incident. A noncrude terminal must demonstrate $55.72 per barrel of total storage capacity or $2.229 million, whichever is greater, up to $111.45 million (18 AAC 75.235(a)(1)–(2); Alaska Department of Environmental Conservation 2023).

The quantity basis differs from the worst-case spill used in Washington and California. Alaska counts the full physical volume of every oil storage tank of 1,000 gallons or more, together with facility piping and excluding permanently closed tanks (18 AAC 75.990). The amount therefore reflects installed capacity and not average inventory or an assumed fill level.

Alaska is also the only West Coast program with an inflation mechanism. AS 46.04.045 adjusts the statutory dollar amounts every third year by the consumer price index for urban Alaska, formerly reported for Anchorage. The current amounts apply through September 30, 2026, and the next adjustment takes effect October 1, 2026 (Alaska Department of Environmental Conservation 2023).

The regulated population is broader than Oregon's. Alaska DEC's approved-facility list runs from small rural bulk fuel facilities near the statutory threshold to refineries and terminals with more than one million barrels of storage (Alaska Department of Environmental Conservation 2026). Program staff count 91 oil terminals, most with 100,000 to 300,000 barrels of capacity (Alaska DEC staff, interview, 2026).

Alaska DEC may seek civil assessments against an operator that fails to demonstrate financial responsibility, halt the operation of a noncompliant facility, and deny entry to or detain a vessel (18 AAC 75.290). Staff describe a graduated practice that begins with letters of noncompliance and notices of violation and proceeds to civil or criminal referral. A terminal that cannot comply may be required to reduce its storage below the volume that defines an oil terminal (Alaska DEC staff, interview, 2026).

4D. Federal Law

The Oil Pollution Act of 1990 establishes both liability limits and financial responsibility requirements, but for different populations. The onshore facility limit of liability applies to all onshore facilities, while the financial responsibility requirements of 33 U.S.C. § 2716 apply only to vessels and offshore facilities. Onshore facilities face no general federal certificate requirement, which is the gap that Washington, California, and now Oregon fill.

The federal limit is a reference point for criterion (F) and for the consistency requirement of §4(2)(i). At $725,710,800, it is approximately 2.4 times Oregon's $300 million maximum.

The Oil Spill Liability Trust Fund provides a federal backstop of up to $1 billion per incident, including up to $500 million for natural resource damage assessment, financed by a per-barrel excise tax on crude oil and imported petroleum products. It is a residual mechanism, and access to it does not reduce the responsible party's obligation.

4E. Industry-Funded Response Funds in Other States

A second group of states finances spill risk through publicly administered, industry-funded response funds, in some cases layered behind facility-level financial responsibility. Maine, Massachusetts, Texas, Louisiana, Florida, and New Jersey levy recurring per-barrel assessments on petroleum or hazardous substances moving through the state, and Virginia pairs a small capacity-based requirement on tank operators with a petroleum storage tank fund. Table 8 summarizes these programs, and Appendix A describes each.

These assessments perform a different function from Washington's $12,500 rate. Washington's rate sizes a stock of financial capacity that a facility must demonstrate before an incident. A fund assessment is a contribution rate that accumulates across transactions, operators, and years to capitalize a common reserve, and several states suspend or raise it according to the fund balance. A five-cent assessment is therefore not an estimate that a spilled barrel causes five cents of damage, and the cents-per-barrel figures are not comparable with the rates in Washington, California, or Alaska.

Table 8: Summary of Comparative Financial Mechanisms

Jurisdiction	Financial Mechanism	Amount	Application	Maximum
Washington	Assurance	$12,500/bbl	Worst-case spill volume	$300M
California				
CA - Marine	Assurance	$12,500/bbl	Reasonable worst-case spill volume	$300M
CA - Inland		$10,000/bbl (perennial waters); $6,000/bbl (intermittent waters)		$100M
Alaska				
AK - Non-Crude	Assurance	$55.72/bbl	Total Storage Capacity	$111.45M
AK - Crude		Flat Requirement	Oil Terminal	$111.45M
Virginia	Hybrid	$2.10/bbl	Aggregate Storage Capacity	$1M assurance[A]
Maine	Fund	$0.61/bbl	Petroleum entering the state	$18.5M
Massachussetts	Fund	$0.05/bbl	Out-of-state petroleum received at marine terminals	$10M (infl-adj)
Texas	Fund	$0.0133/bbl (normally); $0.04/bbl (in catastrophes)	Crude oil/condensate transferred at marine terminals	$20M[B]
Louisiana	Fund	$0.0025/bbl (normally); $0.005/bbl (replenishment rate)	Crude oil received by refineries	$30M[C]
Florida	Fund	$0.02/bbl (normally); $0.10/bbl (after catastrophic damage)	Covered pollutant throughput	$50M[D]
New Jersey	Fund	$0.023/bbl (petroluem); 1.53% of Fair Mkt. Value (other)	Transfers at major facilities	No ceiling[E]

Note:

A. Viriginia: $1M is the maximum facility-specific financial-responsibility requirement; the Petroleum Storage Tank Fund is a separate financing requirement.

B. Texas: $20M is the fee-suspension threshold, not a cap; collection stops after the unencumbered balance exceeds $20M and resumes below $10M

C. Louisiana: The Oil Spill Contingency Fund may not exceed $30M except during a declared emergency or disaster caused by an unauthorized discharge.

D. Florida: $50M is the ordinary capitalization threshold, $100M cap applies to a special offshore-drilling provision.

E. New Jersey: The Spill Compensation Fund is a non-lapsing revolving fund with no fixed statutory ceilings.

The funds share features relevant to Oregon. They make money available before liability, insurance coverage, or allocation among responsible parties is resolved. They pool low-frequency losses across an industry and over time, and several recapitalize automatically when balances fall. Use of a fund does not extinguish responsible-party liability, and the states retain authority to recover their expenditures. New Jersey's fund also reaches hazardous substances other than petroleum, which HB 4100 likewise covers.

For HB 4100, the relevance of these funds begins where the certificate ends. Where a defensible facility-specific calculation exceeds the $300 million maximum, or where money is needed after a correlated multi-facility release before responsibility can be allocated, a pooled fund is the instrument other states use for the residual layer. Establishing one would require legislation.

5. Environmental Sensitivity of Areas where Terminals Operate

Criterion (D) directs evaluation of the environmental sensitivity of the areas where terminals operate. Because §3(5) includes both response costs and natural resource damage assessment and restoration, sensitivity bears on the amount through two channels. A sensitive receiving environment is costlier to clean, and it independently raises the assessment and restoration component of the liability.

Sensitivity is distinct from the probability that a release reaches the environment. Proximity to surface water governs exposure and transport, whereas sensitivity describes the consequence once a receiving environment is exposed. Spill planning practice reflects the distinction. The Environmental Sensitivity Index compiles shoreline habitat type, sensitive biological resources, and human-use resources, and it ranks shorelines from 1 to 10 by exposure to wave and tidal energy, substrate, slope, biological productivity, and ease of cleanup (NOAA 2019). A terminal's distance from water indicates which environment would be affected but not how sensitive that environment is.

The criteria of §4(2)(a) can be read against the same sequence. Criteria (A) and (B) describe the source: terminal type, size, operational risk, and maximum volume. Spill modeling describes the pathway. Criterion (D) describes the receiving environment, and criterion (C) prices the consequence.

5A. Sensitivity of the Lower Willamette Reach

The reach adjoining the Hub is sensitive on each of the three dimensions in the index. It is a federally maintained navigation channel with armored and riprapped banks, and it lies within the Portland Harbor Superfund site. A release would enter water that already carries sediment contamination under an active remedial program. Response would have to be coordinated with that remedy, and the baseline against which injury is measured would be contested.

The lower Willamette supports listed salmonid runs and serves as the migration corridor between the upper basin and the Columbia River. The consequence assessment translates that status into restoration quantities: 175 to 418 acres of wetland to compensate for habitat injury and a further 39 to 1,219 acres of constructed wetland for avian injury. Restoration costs range from $39.7 million to $304.3 million, and total natural resource damages, including assessment, range from $87 million to $669 million (ECONorthwest 2022). The upper figures correspond to a winter release and the lower to a summer release. The same volume of the same product thus produces damages that differ by more than a factor of seven by season.

Human-use sensitivity follows from the public assets and tribal trustee interests identified in Chapter 2, which are concentrated in the same six-mile reach as the tanks. Sensitivity is not uniform across the regulated population, however. Other covered terminals sit on the upper Willamette at Eugene or on the Columbia at Port Westward, and some have no frontage on a perennial water body. Criterion (D) therefore distinguishes among terminals. The consequence assessment offers a classification suited to that purpose: it assigns every tank at the Hub to one of three damage zones by distance from water, with thresholds that vary by area (Table 9).

Table 9: ECONorthwest Damage Zone Classification

Location	Damage Zone (distance from water in feet)		
	In water	**Potentially in water**	**On land**
Area 1, Kinder Morgan North	0 - 500	500 - 750	750+
Area 2, Linnton North	0 - 500	500 - 750	750+
Area 2, Linnton South	0 - 500	500 - 750	750+
Area 3, NW Natural	0 - 250	250 - 500	500+
Area 4, Willbridge	0 - 250	250 - 500	500+
Area 5, Equilon	Not applicable	Not applicable	All

Source: ECONorthwest (2022)

5B. Sensitivity as a Determinant of Unit Costs

Sensitivity can enter a financial assurance calculation as a coefficient applied to a monetary amount or as the variable that selects the amount. This section makes a case for the latter. Every unit cost examined in this report was estimated from releases into specific receiving environments, so the rate already embeds sensitivity, and multiplying by a sensitivity coefficient would price the same attribute twice. No sources examined express sensitivity as a ratio of costs, which is what a coefficient requires. Two programs instead express it as a schedule: California selects $10,000 or $6,000 per barrel according to whether the water at risk is perennial or ephemeral (14 CCR 791.7), and Washington grades natural resource damage compensation by water type and habitat condition (WAC 173-183-610, -620). A schedule is also easier to administer. A coefficient invites dispute over its value, which evidence cannot resolve, whereas a class invites dispute over membership, which facility records can.

One feature of the Washington schedule is particularly nuanced for environmental sensitivity determinations in Oregon. Its habitat index reduces calculated damages based on existing degradation of the receiving water, scoring urbanization, riparian condition, channel modification, and streambed condition. The resulting index modifies the receiving water's vulnerability score, which enters the calculation of damages for injuries that cannot reasonably be quantified (WAC 173-183-600, -850). Consequently, otherwise comparable releases may yield different assessments depending on the receiving environment's pre-spill condition.

Applied to a channelized, urban reach under a Superfund remedy, the index would substantially reduce the figure for the CEI Hub. The lower Willamette is a heavily modified industrial waterway within the Portland Harbor Superfund site, where historical contamination and ongoing remediation complicate attributing new environmental injuries. A habitat index reflecting those conditions could reduce the calculated natural resource damage component without indicating a corresponding reduction in response and cleanup costs. Existing contamination does not necessarily make a new release less costly to contain or remediate, particularly where response must be coordinated with ongoing cleanup activities.

That result is consistent with damage assessment, which measures marginal injury to a resource from its pre-spill condition, but it does not map as neatly onto financial assurance, which must also cover response costs, because a degraded reach is not cheaper to clean. Consequently, if the EQC draws on the Washington schedule, it is recommended that an Oregon-specific class structure be considered, that appropriately accounts for questions of degradation.

6. Market Capacity and the Reliability of Financial Assurance

Criterion (E) requires the EQC to evaluate commercially available financial assurance mechanisms, including the maximum coverage offered. Unlike the volume and cost criteria, commercial availability supplies no per-barrel input. It tests whether the amount indicated by the risk and cost evidence can be demonstrated in practice. Because HB 4100 permits mechanisms to be used alone or in combination, the capacity of a single instrument is not the binding constraint (§4(2)(a)(E), (b)).

6A. Market Capacity and Combined Demonstrations

Washington's 2024 rulemaking is the most useful benchmark. Ecology concluded that oil spill insurance for onshore facilities had a practicable upper limit of approximately $200 million and that surety bonds were generally unavailable at comparable levels. Washington nonetheless requires its largest facilities to demonstrate $300 million, with the amount above insurance capacity assembled from other approved mechanisms, including self-insurance (Posewitz et al. 2024).

The same analysis shows how market capacity entered the decision. Ecology found that the $27,200 alternative would become progressively more burdensome as facilities moved beyond readily available commercial coverage (Posewitz et al. 2024), and it cited the availability of obtainable financial responsibility in rejecting the $60,153 proposal (Washington State Department of Ecology 2024a). The adopted requirement thus reflects the cost and practicality of demonstration as well as estimated spill consequences.

Program experience in other states indicates that demonstrations are commonly assembled from several mechanisms. California staff report that roughly 70 percent of demonstrations rely on insurance and 25 percent on self-insurance, that facilities at the $300 million maximum usually self-insure, and that insurance availability has not been a constraint for facilities of that size (OSPR staff, interview, June 30, 2026). Alaska staff report that most terminals rely on private insurance, followed by parent-company guarantees, and that some combine several policies with a surety bond (Alaska DEC staff, interview, 2026). Alaska's much lower requirement limits its value as evidence of capacity near $300 million.

The $200 million estimate is not a market constant. In the Vancouver Energy Terminal proceeding, the applicant presented evidence that insurance programs of approximately $1 billion to $1.5 billion might be available for that project (EFSEC 2017). The council did not find that the applicant had demonstrated sufficient coverage, but the evidence suggests that available capacity varies with the insured, the coverage structure, and market conditions.

Market capacity also shapes the structure of what is demonstrated. Meeting a requirement entirely through primary and excess insurance forms an insurance tower, while meeting it through insurance together with self-insurance, a guarantee, or a letter of credit forms a combined demonstration. The distinction matters because a certificate's reliability depends on the collectability and continuity of its instruments as well as on its stated amount.

6B. Implications for the Financial Assurance Requirement

The face value of a financial assurance instrument does not necessarily equal the amount available after a release. Coverage may be reduced or delayed by deductibles, exclusions, gaps between insurance layers, cancellation provisions, or limits shared across facilities. Washington addresses several of these risks by requiring applicants to provide the policy, disclose conditions and limitations affecting spill coverage, identify deductibles and self-insured retentions, and separately assure any deductible exceeding 1 percent of the policy limit (WAC 173-187-220(6)(a)).

Exclusions for earthquakes or other natural hazards are particularly important in Oregon. HB 4100 does not expressly state how such exclusions are to be treated, but earthquake-triggered releases are a central part of the risk facing many covered terminals. An approved mechanism could therefore meet the required amount on paper while providing less protection if the release-triggering event is excluded. It is recommended that DEQ verify that exclusions do not prevent an instrument from responding to otherwise covered spill-related liabilities. Alaska staff described required endorsement language as one way its program addresses this issue (Alaska DEC staff, interview, 2026). Where a terminal uses several layers of financial assurance, it is recommended that DEQ review continuity of coverage and gaps left by exclusions or exhausted limits before approving the layers. Washington requires disclosure of policy terms but does not prescribe how excess layers must respond when an underlying layer is unavailable. Guarantees, surety bonds, letters of credit, and similar mechanisms raise a different question: whether the funds can actually be reached if the operator cannot or will not pay. Washington addresses this by requiring standby trusts for several of these mechanisms and directing payments into the trust (WAC 173-187-220(6)(b)–(e)).

Shared limits create another concern where losses occur at several facilities at once. Washington allows one certificate to cover several facilities of the same owner, and California permits one instrument to support several certificates (WAC 173-187-200(3); OSPR staff, interview, June 30, 2026). In a correlated event such as a major earthquake, several facilities could therefore make claims against the same policy or guarantee. The relevant question is not

the nominal amount assigned to each certificate, but how much remains available when those claims occur together.

Reducing the required amount may make financial assurance easier to obtain, but it does not reduce the underlying spill exposure. Oregon does not maintain a state response fund comparable in size to the $300 million certificate maximum. Other funding sources may be available after a spill, but they do not replace the assurance a terminal must demonstrate. If that assurance is unavailable or insufficient, some costs may fall to public entities or other recovery mechanisms.

Chapter 3 describes the scale of potential liabilities. Table 10 instead examines whether financial assurance was actually available when it was needed; these cases show how the amount stated on paper differed from the amount that could ultimately be collected.

Table 10: Selected Cases on Financial Assurance Performance

Case	Location (year)	Context	Mechanism	Observed issue	Relevance
M/V New Carissa	Oregon (1999)	Vessel Oil Spill	Federal COFR + P&I insurance	RP settlement did not fully fund restoration; OSLTF supplied additional funding	Assurance + public backstop
T/V Margara	Puerto Rico (2006)	Vessel / NRD	Federal COFR guarantor	Guarantor declined claim; OSLTF paid additional funding	Access to funds
Alabama Plating	Alabama (1985–2004)	Hazardous-waste Cleanup	Letter of credit + Trust	Bank disputed access to funds	Enforceability
Paradise Peak	Nevada (1995–2004)	Mine Reclamation	Corporate guarantee + Surety	Guarantee failed in bankruptcy; cost estimate also increased	Provider and amount risk
Enbridge Line 6B	Michigan (2010)	Pipeline Oil Spill	Pollution Insurance	Shared $650M aggregate; coverage exhausted and part disputed	Shared limits / coverage risk

Sources: National Pollution Funds Center (2019); *US v. Ernst Jacob GmbH & Co. KG* (2025); National Pollution Funds Center (2007); *Green Atlas Shipping S.A. v. US* (2003); *Childersburg Bancorporation v. Alabama Dept of Env. Mgmt.* (2004); GAO (2005); Enbridge Energy (2018)

The key issue is not nominal coverage, but whether funds remain accessible when needed. In the cases reviewed, guarantees, draw restrictions, weakened self-assurance, and shared limits reduced the amount available. For criterion (E), commercial capacity therefore includes both the amount that can be assembled and its reliability over time. HB 4100 supports this through periodic renewal, self-insurer reporting, and DEQ verification (§4(2)(d), (g), (h)).

7. Considerations on Financial Assurance Requirements

The preceding chapters identify what drives potential spill-related liability and what makes a demonstration of financial assurance credible. This chapter combines those findings to calculate the required amount.

Each criterion in §4(2)(a) informs part of that calculation:

- **Criterion (A).** Terminal type, size, and operational risk inform the spill quantity, *Q*.
- **Criterion (B).** Maximum volume handled also informs *Q*.
- **Criterion (C).** Historical and projected costs inform the unit cost, *U*.
- **Criterion (D).** Environmental sensitivity also informs *U*.
- **Criterion (E).** Commercially available financial assurance mechanisms test whether the resulting amount can be demonstrated in practice.
- **Criterion (F).** Requirements in other jurisdictions provide regulatory benchmarks for the calculation.

Read literally, the statutory criteria could support a more elaborate calculation in which terminal characteristics and volume define exposure, historical cost and environmental sensitivity adjust its monetary consequence, other jurisdictions provide a comparative weighting, and commercial availability bounds the result:

$$\text{Calculated Amount} = (A \cdot x + B \cdot y) \times C \times D \times F$$

with commercial availability under criterion (E) bounding the result and the statutory maximum applied separately:

$$\text{Required Financial Assurance} = \min[\$300M, \text{Calculated Amount}]$$

The preceding chapters support the logic of this structure but not separate numerical coefficients for each criterion. The relevant literature does not provide defensible universal weights for facility risk and volume, a single environmental-sensitivity multiplier, or a numerical weighting for other jurisdictions. Applied to Oregon terminals, for example, the Washington and Alaska methods produce amounts that differ by factors of 17 to more than 200, making criterion (F) unsuitable as a numerical weighting factor.

The calculation can therefore be reduced to two terms: a spill quantity, *Q*, in barrels, multiplied by a unit cost, *U*, per barrel. Criteria (A) and (B) inform *Q*; criteria (C) and (D) inform *U*; criterion

(F) provides regulatory benchmarks; and criterion (E) tests whether the resulting amount can be demonstrated.

The two terms are not equally suited to facility-specific adjustment. *Q* describes physical exposure and can be refined through engineering evidence about operating limits, containment, mitigation, and credible release scenarios. *U* represents a regulatory estimate of the consequences of a released barrel and is better maintained as a common benchmark unless sufficient evidence develops to differentiate it.

Applied to the current terminal inventory, the $300 million maximum, rather than the choice of unit cost, determines the initial requirement for twelve of the thirteen terminals with a worst-case spill volume reported to DEQ. The unit cost remains consequential for PDX Fuel Company, for terminals without a verified volume, and for future entrants, and it determines the calculated amount at every terminal.

The empirical evidence does not support reducing the unit cost below $12,500 per barrel. The rate is a 1991 administrative figure that has lost more than half of its real value; the in-scope components of the Mercer estimate approach $35,000 in 2026 dollars; natural resource damage settlements alone average $8,350 per barrel; and no available per-barrel estimate prices fire damage. None of these figures provide a complete Oregon-specific unit cost, however. As an initial benchmark, this report therefore retains $12,500 per barrel. It preserves regional consistency with Washington, and because the statutory maximum already binds at twelve of thirteen reporting terminals, a higher rate would change the initial required amount at only one.

The sections below apply the same $Q \times U$ structure with progressively better information. The initial rule uses standardized inputs available for the 2027 application cycle. The differentiated review describes how facility-specific evidence could first refine *Q* and, where sufficient evidence develops, later inform *U*. The mature framework describes a longer-term structure in which both terms are supported by Oregon-specific evidence.

7A. Recommended Initial Rule

The Significance of Spill Volumes

Existing records offer two quantity bases. Alaska uses total storage capacity, while Washington and California use the worst-case spill volume, or WCS (18 AAC 75.235; WAC 173-187-110; 14 CCR 791.7). Table 11 reports both for the terminals subject to HB 4100, with the amount each method would require.

Table 11: Quantity Bases and Financial Assurance Requirements Based on AK and WA Rules

Terminal	Reported WCS (bbl)	Total capacity (bbl)	WCS share of capacity	Alaska FA ($M)	Washington FA ($M)
Kinder Morgan Willbridge	121,000	1,550,000	8%	86.4	1,513
Zenith Energy	151,000	1,518,200	10%	84.6	1,888
NuStar Shore Terminals	100,000	1,192,857	8%	66.5	1,250
Chevron Willbridge	147,619	1,090,476	14%	60.8	1,845
McCall Oil & Chemical	280,000	904,762	31%	50.4	3,500
Phillips 66	82,000	854,762	10%	47.6	1,025
Kinder Morgan Eugene	58,000	707,143	8%	39.4	725
Seaport Midstream Partners	106,000	588,095	18%	32.8	1,325
Kinder Morgan Linnton	73,000	416,667	18%	23.2	913
PGE Beaver Plant	N.A	295,238	N.A	16.5	n.r.
Pacific Terminals Services	80,000	276,190	29%	15.4	1,000
Triton West (Shell)	N.A	276,190	N.A	15.4	N.A.
Owens Corning Roofing and Asphalt	N.A	185,714	N.A	N.A.	N.A.
Cascade Kelly Holdings	90,000	178,571	50%	9.9	1,125
NW Natural	175,000	176,190	99%	9.8	2,188
PDX Fuel Company	20,000	60,000	33%	3.3	250

Note: NA = Not Available. FA amounts reported in millions. The Alaska FA applies $55.72 per barrel of total capacity, with a $2.229 million floor and a $111.45 million ceiling. The Washington FA applies $12,500 per barrel of WCS. Quantities are working values pending verification.

Total capacity has clear advantages. It is a physical attribute that an operator cannot restate, and it requires no modeling. It also reflects the Cascadia scenario, in which liquefaction and lateral spreading are expected at every tank location in the Hub (Dusicka and Norton 2019). Its weakness is that no cost rate is expressed per barrel of capacity. Every per-barrel figure in Chapter 3 is a cost per barrel released, and the capacity-based rates in use, Alaska's $55.72 and Virginia's $2.10, are not estimates of spill cost. Applying $12,500 to total capacity would assume that every tank is full and releases its entire contents, whereas the consequence assessment models a release of 28 to 58 percent of active capacity (ECONorthwest 2022).

The WCS is the better basis for the initial calculation. Oregon's contingency planning rules already define it as the largest foreseeable spill in adverse weather, thirteen of the sixteen terminals in the working inventory report one to the DEQ, and it is the quantity to which the $12,500 rate was designed to apply (OAR 340-141-0005; WAC 173-187-110).

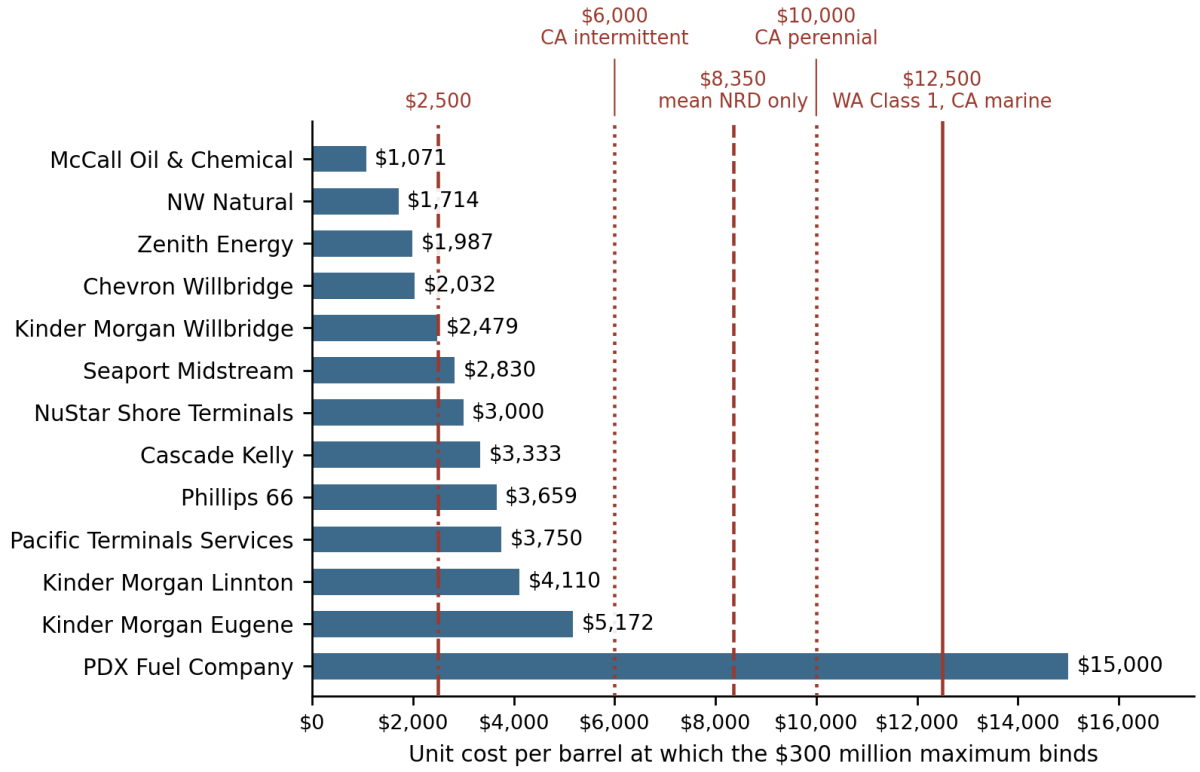
Reported WCS values are not yet comparable, however. They range from 8 to 99 percent of total capacity and reflect different operating limits and planning assumptions. As a result, a standardized certificate quantity, defined as the verified WCS but no less than the largest in-service tank's full capacity, is preferred. This is also Washington's default for Class 1 onshore facilities (WAC 173-187-040). Largest-tank capacity is a conservative proxy for a potential release rather than an estimate of the fraction released.

A largest-tank WCS does not capture the correlated failure of several tanks in a Cascadia event. For twelve of thirteen terminals, however, a larger quantity would raise only the uncapped calculation, because the maximum already determines the required amount. Therefore, incorporating a correlated release estimate at the differentiated review, once seismic vulnerability assessments become comparable, is recommended. Recording total capacity and the uncapped amount in the certificate file preserves that information for the differentiated review.

The Statutory Maximum and Unit Cost

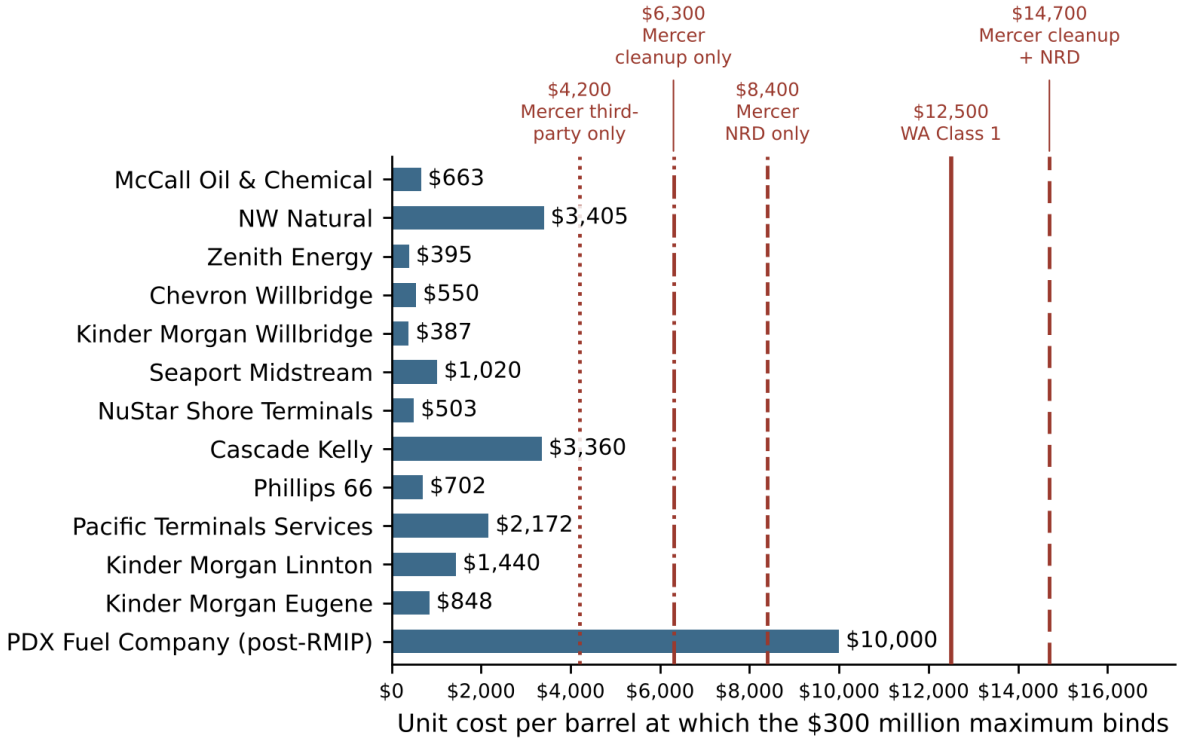
For a terminal with design quantity *Q*, the maximum binds at any unit cost above $300 million divided by *Q*. Figure 2 plots that threshold for the thirteen terminals with a reported WCS. Twelve reach the maximum at $5,172 per barrel or less, and the median terminal reaches it at $3,000. Only PDX Fuel Company, at 20,000 barrels, remains below the maximum at $12,500. Every rate with regulatory precedent on the West Coast therefore produces the same requirement at twelve of thirteen terminals, and moving from Washington's $12,500 to California's $10,000 or $6,000 changes the amount at PDX Fuel alone. The unit cost would have to fall below $3,000, a 76 percent reduction from the Washington rate, to affect a majority of terminals, and below $1,071, a 91 percent reduction, to release every terminal from the maximum.

Figure 2: Unit Cost at Which $300 Million Statutory Maximum Binds under the WCS Quantity Basis, by Terminal



The result does not depend on the WCS basis. Figure 3 repeats the calculation with the quantity set at half of total capacity, a share within the range of active capacity that the consequence assessment models as released (ECONorthwest 2022), and keeps the terminal order of Figure 2. Every terminal other than PDX Fuel Company reaches the maximum at $3,405 per barrel or less, and the median terminal reaches it at $848. PDX Fuel Company reaches it at $10,000, so all thirteen terminals reach the maximum at $12,500 and at California's perennial-water rate. Mercer's cleanup and natural resource damage components, each taken alone and in 1992 dollars, exceed the binding rate at every terminal except PDX Fuel Company.

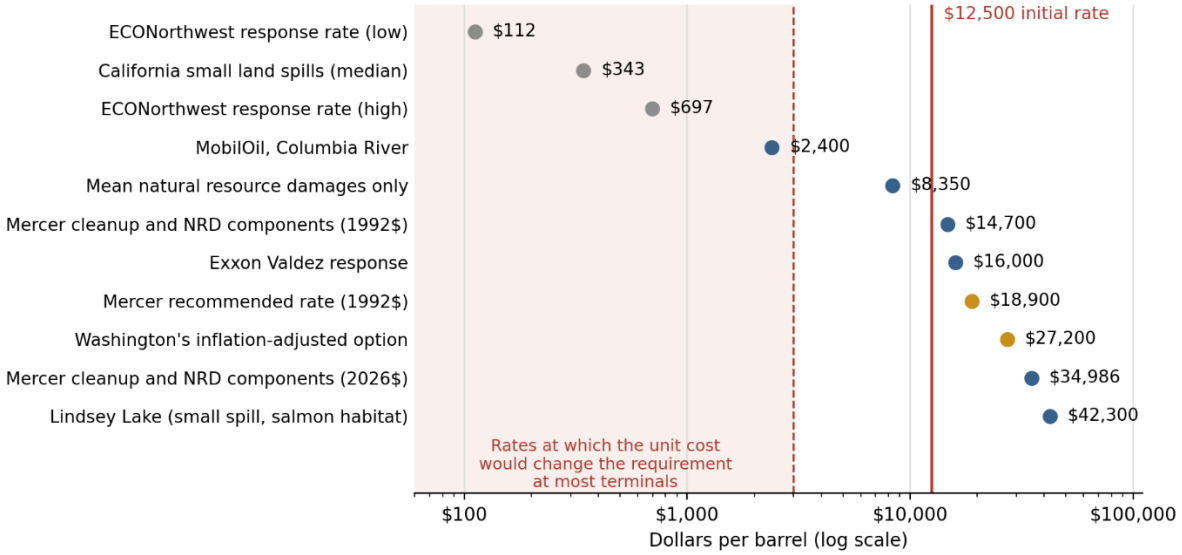
Figure 3: Unit Cost at Which $300 Million Statutory Maximum Binds at 50 Percent of Total Capacity, by Terminal



Note: Terminals appear in the order of Figure 2. Quantity is half of the total capacity reported in Table 11; PDX Fuel Company is shown at its capacity after its risk mitigation implementation plan (RMIP). Mercer (1993) components are per-gallon estimates in 1992 dollars converted at 42 gallons per barrel. Capacities are working values pending verification.

Nothing in the preceding chapters supports a rate low enough to change the result for most terminals. Figure 4 arrays the per-barrel evidence on a logarithmic scale against a shaded band of rates below $3,000. Four observations fall inside the band, and each prices a single cost component or a different kind of event. The ECONorthwest rates of $112 and $697 are response-only figures averaged over a modeled release of several million barrels, and the study monetizes neither fire nor the degraded response environment after an earthquake (ECONorthwest 2022). The California survey median of $343 describes spills under 100 barrels that never reached flowing water (Catalyst Environmental Solutions et al. 2019), and the MobilOil figure of $2,400 is a 1984 response cost with an uncertain volume (Park 1985). Section 3(5), by contrast, covers response, fire damage, and natural resource damages together. The mean natural resource damage settlement alone is $8,350 per barrel before any response cost is added (Hodgdon and Industrial Economics 2023), and the two in-scope components of the Mercer estimate total about $35,000 in 2026 dollars (Mercer Management Consulting 1993).

Figure 4: Selected Per-Barrel Unit Costs against Thresholds and Regulatory Benchmarks



Regulatory precedent points the same way. The lowest worst-case-spill rate in any comparator program is California's $6,000, which applies only where the water at risk is intermittent or ephemeral, and no terminal on the lower Willamette fits that description (14 CCR 791.7). The lowest rate applicable to a perennial river is $10,000. Pressure on the $12,500 rate has otherwise been upward: Mercer recommended $18,900 in 1993, Ecology evaluated $27,200 in 2024, and a commenter in that rulemaking proposed $60,153. A rate low enough to change the result for most terminals would have to be chosen for the distribution it produces, because neither the cost evidence nor any comparator rule supplies one.

Alaska's Capacity-Based Minimum Requirement

Alaska's method is the one comparator approach that would keep every Oregon terminal below the maximum. Applied to Oregon, $55.72 per barrel of total capacity yields $3.3 million to $86.4 million per terminal (Table 11), and the uncapped Washington calculation for the same terminals is 17 to more than 200 times larger.

The Alaska rate is not a cost estimate. It descends from a $25 per barrel figure set in statute in the early 1990s and has since changed only through indexation (AS 46.04.045), and program staff could not identify an empirical basis for the original value (Alaska DEC staff, interview, 2026). Because it applies to installed capacity, it cannot be read as a cost per barrel released. The program also serves a different population under a much lower ceiling. Its $111.45 million maximum is below the reported cost of the CITGO Lake Charles release of about 54,000 barrels, and twelve of thirteen Oregon terminals report a larger WCS than that. The statute points the same way, since it directs the EQC to consider Washington's requirements and adopts

Washington's $300 million maximum (§2(4)(b), §4(3), §4(4)(a)). Alaska's method is informative about regulatory structure, particularly indexation, but not about cost.

Recommended Initial Benchmark

It is recommended that the initial rule follow Washington's Class 1 calculation. Under that calculation, each terminal demonstrates $12,500 per barrel of verified WCS, using a design quantity not less than the capacity of its largest in-service tank, up to $300 million. It provides a common starting point using quantities already reported to DEQ.

Under the initial rule, the financial assurance requirement therefore depends on two standardized terms: the spill quantity, *Q*, and the unit cost per barrel, *U*. The initial *Q* is the verified WCS, subject to the largest-tank floor, and the initial *U* is $12,500 per barrel. If DEQ incorporates facility-specific differentiation, the recommended starting point is *Q*. The quantity term describes physical exposure that can be evaluated through engineering evidence, while *U* represents a common regulatory estimate of the consequences of a released barrel. For petroleum terminals, it is therefore recommended that facility-specific alternatives operate through *Q*, with operator-funded third-party analysis subject to DEQ review and approval, rather than through a facility-selected unit cost.

Non-petroleum inventories present a separate issue because a petroleum-based unit cost may not adequately describe their consequences. For the initial cycle, the $12,500 rate can serve as a provisional benchmark for liquefied natural gas at NW Natural and asphalt at Owens Corning. Material-specific consequence methods can then be considered as part of the differentiated review. This provisional treatment does not affect NW Natural's initial requirement because it reaches the $300 million maximum at $1,714 per barrel.

It is recommended that each certificate report both the calculated and the required amount, because the calculated amount carries information that the maximum removes. At $12,500 per barrel, calculated amounts range from $250 million to $3.5 billion and total roughly $18.5 billion across the reporting terminals, compared with $3.85 billion required after applying the statutory maximum. The difference measures the exposure above the maximum and provides information for DEQ's first evaluation under §4(4)(b). The total indicates the gap between the regulatory calculation and certificate limits; it is not a modeled estimate of losses from a single Cascadia earthquake, which would require joint failure scenarios.

Covered terminals already prepare seismic vulnerability assessments under ORS 468B.510. Linking those assessments to the certificate file would allow later calculations to incorporate correlated failure, operating limits, containment, and verified mitigation without creating a

separate engineering framework. Table 12 lists tank-level fields that can be collected with the 2027 application and later used to incorporate correlated failure, operating limits, containment, and verified mitigation.

Table 12: Shared Inputs Between Seismic Vulnerability Assessments and COFR Requirements

Shared field	Relevance for 2027	Relevance for 2030
Tank identifier and capacity	Verify the WCS and the largest-tank floor; record total capacity	Assign scenario inventory; join assessment updates to the certificate
Product and enforceable operating limit	Confirm any limit relied on to reduce the design quantity	Assign product class; credit verified limits
Common-cause failure group	Record which tanks the assessment models as failing together	Define the correlated capacity in the design quantity
Ground-failure and structural failure modes	Recorded only; no adjustment to the amount	Estimate release fractions or a correlation coefficient
Scenario-specific release fractions	Recorded where already modeled	Incorporate modeled release in estimation
Containment and pathway assumptions	Record whether secondary containment is independent and operable	Support the pathway class and mitigation credit
Mitigation status and effective date	-	Reduce the modeled release where performance is demonstrated

7B. Intermediate Differentiated Review

DEQ may not evaluate or adjust the $300 million maximum before January 1, 2030 and must evaluate it every three years thereafter (§4(4)(b), §7). Certificates issued in 2027 come up for renewal on the same three-year cycle, and the EQC must periodically update the minimum amounts for inflation, industry changes, emerging risks, and lessons from response (§4(2)(g)(A), §4(5)). Because §4(5) leaves the timing of those updates to rule, it is recommended that the initial rule set an update schedule aligned with renewals and with the three-year evaluation of the maximum.

The first review after January 1, 2030 can therefore reconsider the design quantity, unit cost, and maximum together. Differentiation proceeds first through *Q*, because seismic vulnerability assessments and facility records can provide engineering evidence about the quantity credibly at risk. *U* remains a common benchmark until a stronger empirical basis develops for differences in cost by product, pathway, or receptor.

The first review can accordingly test four refinements: indexation of the common benchmark, improved facility-specific release quantities, collection of product and pathway information for possible future cost differentiation, and alternative consequence methods for materials that a petroleum rate does not adequately describe. Appendix B presents an illustrative schedule only, because Oregon analyses characterize release pathways, seismic consequences, and aggregate damages but do not estimate unit costs by pathway, product, and receptor (ECONorthwest 2022). Developing such estimates would require linking facility-specific release scenarios to

consequence and cost components, as scenario-based Natech methods and empirical spill-cost research do (Antonioni et al. 2009; Girgin and Krausmann 2013; Kontovas et al. 2010).

Indexation. Neither Washington nor California indexes its rate or maximum, while Alaska adjusts its amounts every third year (AS 46.04.045). If both terms are indexed from a common Oregon base year, applying the same index would preserve the quantity at which the maximum binds; indexing either term independently would change it.

Correlated release quantity. The seismic vulnerability assessments could eventually support a design quantity that accounts for several tanks failing in the same earthquake, consistent with Natech research on multiple related equipment failures (Antonioni et al. 2009; Krausmann et al. 2017). Existing assessments are not yet consistent enough for that purpose, because they characterize ground conditions and seismic deformation with different assumptions and methods.

Once tank-level results are reported consistently, the design quantity could, as a screening sensitivity, add to the largest tank an evidence-based share of other capacity exposed to the same failure mechanism (Appendix B, Table B4). This makes *Q* the principal facility-specific lever in the differentiated framework. An operator could support a different quantity through operator-funded third-party engineering analysis subject to DEQ review and approval. It is recommended that such an analysis begin from the credible release quantity rather than from a requested financial assurance amount.

Pathways. The pathway classes extend the damage zones in the Oregon consequence assessment, which sorts tanks by distance from the river and by topography into material in water, potentially in water, and on land (ECONorthwest 2022) (Table 9). The assessment places 96 tanks in the first two zones, releasing 40.8 million to 82.5 million gallons, and 269 tanks on land, releasing 53.9 million to 111.2 million gallons.

- **W1, direct water pathway.** A credible release under the design scenario reaches perennial or navigable surface water without an intervening barrier.
- **W2, indirect or conveyance pathway.** A release does not discharge directly to surface water but can credibly reach it through drainage, overland flow, or other conveyance.
- **W3, contained land pathway.** No credible pathway to surface water exists under the design scenario.

The classes turn on whether a release reaches surface water and by what route. California's inland test, whether the water at risk is perennial or ephemeral, would not distinguish among

terminals sited on the Willamette and the Columbia. Assigning a class to an individual terminal would require information on tank location, containment, drainage, and other conveyance. Seismic vulnerability assessments, contingency plans, and facility files could provide that information. Until then, the available assessment supports pathway distinctions across areas of the Hub but not defensible facility-specific rate assignments (ECONorthwest 2022). It is therefore recommended that pathway initially be collected as a reporting variable rather than used to modify *U*.

Potential unit-cost differentiation. A later framework could differentiate *U* through a schedule based on product persistence, release pathway, and receptor condition rather than through separate multipliers, which could count the same consequence more than once. Empirical research finds that spill costs do not scale proportionally with volume and that product and location materially affect total cost (White and Molloy 2003; Kontovas et al. 2010). Product persistence has the strongest support, since the California cost study reports a fourfold difference in modeled per-barrel costs across persistence classes at the same volume (Catalyst Environmental Solutions et al. 2019). Pathway and receptor differentials are less certain because they rely on comparator ratios and damage schedules rather than Oregon observations. The schedule in Appendix B is therefore illustrative rather than a proposed set of rates.

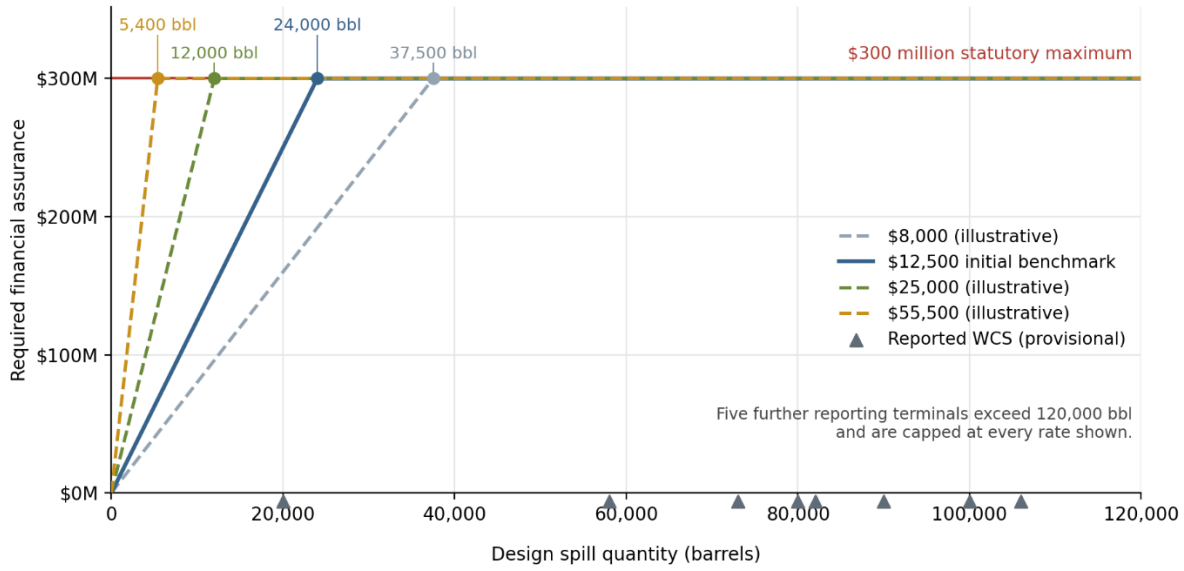
The consequence assessment provides a check on the initial rate. It models 43 percent of the released volume reaching water under both bounding scenarios, and pricing the water-bound and land-bound fractions separately yields a blended rate of $12,350 to $13,600 per barrel for light persistent product (Appendix B, Table B2). That range brackets $12,500, but it is an illustrative consistency check rather than independent validation, since it combines transferred California costs, a modeled Oregon water share, and a land cost from a different incident. Federal spill-cost modeling similarly distinguishes costs by affected medium, proximity to water, and ecological receptors (Pipeline and Hazardous Materials Safety Administration 2023). Because the water share describes a facility-level scenario rather than an individual tank, this analysis is better used to test the common benchmark than to assign a facility-specific rate.

Alternative amounts and other materials. Non-petroleum inventories present a separate issue because the petroleum-based $Q \times U$ framework may not describe their dominant consequences. Renewable diesel and certified drop-in fuels can take the petroleum rate directly where specification equivalence is established. Biodiesel and asphalt support more limited analogues, and ethanol requires separate treatment because it behaves differently in water. Liquefied natural gas requires an engineered consequence estimate, since its consequence pathways include dense-gas dispersion, thermal radiation, pool fire, and rapid phase transition

(Hightower et al. 2004; Luketa-Hanlin 2006). Appendix B assigns each material a transfer basis (Table B5).

Effect under the current maximum. Figure 5 shows where a differentiated rate could change the required amount. Each line gives the required amount as a function of design quantity at one rate. The amount rises with quantity until the $300 million maximum binds, and that quantity falls as the rate rises: 37,500 barrels at $8,000 per barrel, 24,000 at $12,500, 12,000 at $25,000, and about 5,400 at $55,500. Beyond it, a change in the rate affects only the uncapped calculation.

Figure 5: Required Amount as a Function of Quantity, by Illustrative Rate



Note: The $12,500 benchmark is in force in Washington and California. The dashed rates are example sensitivities derived in Appendix B and are not proposed rates. Reported worst-case spill volumes are provisional pending verification. This figure does not imply a level for the statutory maximum.

The practical effect of differentiating *U* under the current maximum is therefore narrow. The lowest illustrated rate binds at 37,500 barrels, and the smallest reported WCS above that of PDX Fuel Company is 58,000 barrels, so twelve of the thirteen reporting terminals are capped at every rate shown. Only PDX Fuel Company remains below the maximum over part of the illustrated range. A differentiated schedule would therefore change the measurement of uncapped exposure much more than the required amount.

Product, pathway, and receptor classes are accordingly better used first as reporting fields than as adopted rates. These data would allow DEQ to test differentiated exposure during its evaluation of the maximum while leaving *U* as a common benchmark until stronger evidence

supports changing it. Facility-specific differentiation can meanwhile proceed through *Q*, where engineering evidence provides a clearer basis for adjustment.

Each refinement depends on information developed during the first certificate cycle. Indexation requires a designated index and base year. Facility-specific adjustment of *Q* requires seismic outputs linked through common tank identifiers. Future differentiation of *U* requires verified product, pathway, and receptor information together with stronger cost evidence. Alternative amounts require material-specific consequence evidence. Evaluation of the maximum requires both the uncapped calculation and current evidence on market capacity.

7C. Long-Term Mature Framework

In a mature program, both terms of the calculation could be refined using Oregon evidence. *Q* would remain the primary facility-specific term, based on a modeled release under common earthquake scenarios, selected by a defined decision rule, and reduced only where installed and verified mitigation demonstrably lowers that release. *U* could then be differentiated where pooled evidence supports systematic differences in response costs, natural resource damages, fire damage, and other public costs by product, pathway, or receptor.

The unit cost would therefore no longer depend primarily on a transferred regulatory benchmark. It could instead be constructed primarily from pooled national evidence, with Oregon cost-recovery data added as it accumulates. It is recommended that fire be priced explicitly, because it falls within §3(5), is characteristic of earthquake-triggered industrial releases, and is absent from the principal per-barrel figures reviewed in Chapter 3 (Krausmann et al. 2017). Fire is better represented as a scenario-specific cost component than as a per-barrel rate, as discussed below. For inventory that a per-barrel rate cannot adequately describe, use an engineered consequence estimate, and evaluate the statutory maximum each cycle against the resulting distribution of calculated exposure.

A mature framework would also address what an individual certificate cannot. Calculated exposure at most terminals exceeds the amount the commercial market has been shown to support, and a Cascadia event could call on multiple certificates and shared limits at the same time. The industry-funded response funds reviewed in Chapter 4 illustrate one approach other states use for residual costs. Establishing such a mechanism would require separate legislative action, but the uncapped amounts reported from 2027 onward would provide evidence relevant to that decision.

Table 13: Inputs to the Minimum Financial Assurance Requirement Alternatives

Stage	Design quantity	Unit cost	Maximum	Required Inputs
Initial rule (applications due March 31, 2027)	Verified WCS, not less than the largest in-service tank	$12,500 per barrel for all covered inventory; nonpetroleum inventory provisional	$300 million	Verified quantities; qualified mechanisms; shared fields with the seismic assessment
Differentiated review (first evaluation after January 1, 2030)	WCS plus correlated capacity where seismic assessments support it	Initial or indexed benchmark; class-specific rates evaluated if supported by Oregon evidence; approved alternative amounts	Evaluated under §4(4)(b)	Reported pathway and product classes; assessment outputs on common tank identifiers; uncapped amounts; market capacity evidence
Mature framework (later three-year cycles)	Modeled release under common scenarios and a defined decision rule, net of verified mitigation	Scenario costs for response, natural resource damages, fire, and other public costs, drawing on pooled national and Oregon cost data; effective rate derived for comparison	Evaluated each cycle against calculated exposure; residual layer met by a pooled fund if enacted	Pooled national cost data and category-level DEQ cost recovery; engineered fire and nonpetroleum consequence estimates; legislation for any fund

The calculation is the same at every stage, and only the evidence behind its inputs changes. Oregon can adopt Washington's calculation in 2027 without foreclosing a more precise program, and it cannot reach a more precise program without the information the initial rule begins to collect.

Data Requirements for the Mature Framework

The mature framework requires three kinds of evidence: an inventory of the material at risk, engineering estimates of its release under specified conditions, and monetary estimates of the consequences. The three differ in scale and in how they can be obtained. DEQ can document the inventory through routine reporting. Release estimates require targeted engineering analysis. Unit costs require observations of actual incidents, which Oregon cannot generate at a useful rate and which must come largely from external research. Table 14 sets out each input by workstream, with its likely scale, what it could support at the first evaluation after January 1, 2030, and what it would not show.

Table 14: Data Requirements for the Mature Framework, by Input

Input	Workstream	Likely scale	Could support by 2030	Would not show
Tank inventory and construction	Routine reporting	16 terminals; roughly 400 active Hub tanks; about 8,000 values at 20 fields per tank	Comparable capacities, tank types, anchorage, roof configuration, and largest-tank quantities	Seismic failure probabilities
Operating inventory	Routine reporting	14,400 tank-months (monthly) to about 438,000 tank-days (daily) over three years	Typical inventory, seasonal variation, and compliance with enforceable fill limits	Inventory at the moment of an earthquake; seismic benefit of reduced fill
Ground conditions	Targeted engineering	Existing assessments plus targeted cone penetration tests where coverage is sparse	Comparable deformation estimates; identification of poorly characterized areas	Actual displacement in a future earthquake
Fragility and loss of containment	Targeted engineering	Hub tank archetypes; empirical curves from roughly 400 to 530 tanks in other earthquakes.	Conditional damage and release estimates; comparison of mitigation options	Locally validated failure and release probabilities
Containment and pathways	Routine reporting and targeted engineering	Containment areas and drainage connections at all terminals	Whether releases could reach land, surface water, or connected drainage	Whether containment and drainage function after severe deformation
Fire and escalation	Targeted engineering	Representative scenarios at facilities and adjoining areas.	Thermal impacts, exposed public assets, and consequences of impaired suppression	A defensible fire cost per barrel
Spill and liability costs	External research	All DEQ incidents plus pooled national evidence; hundreds to thousands of comparable incidents to differentiate many classes	Better cost categorization and selected response-cost benchmarks	Oregon-specific catastrophic costs or reliable rates for many classes
Financial assurance mechanisms	Routine reporting	About 16 applications in 2027 and 16 renewals in 2030, plus quarterly reports from self-insured operators (§4(2)(d)(B))	Coverage arrangements, exclusions, deductibles, and shared limits	Collectibility after a major correlated event

Note: Scale figures are order-of-magnitude planning estimates, not published minimum sample requirements. Twenty fields per tank and monthly or daily reporting are assumptions. Routine reporting can be required of operators; targeted engineering requires specialized analysis where current assessments are insufficient; external research cannot be generated through certificate administration.

Inventory and operating conditions. The working inventory comprises sixteen terminals, and the Hub alone holds roughly 400 active tanks (ECONorthwest 2022). With a common tank identifier across certificates, contingency plans, seismic vulnerability assessments, and risk mitigation implementation plans, a record of twenty attributes per tank would hold about 8,000 values, most of them stable physical characteristics verified once and updated at renewal. Operating inventory requires repeated observation. Monthly records over three years would amount to 14,400 tank-months, and daily records to about 438,000 tank-days. These are administrative volumes, not independent observations of seismic performance. They can show

normal operating ranges, seasonal variation, and consistency with an operating restriction, but historical inventory does not fix the maximum quantity available for release. An enforceable fill limit with operating controls and verification is the stronger basis for a lower design quantity. The seismic benefit of reduced fill also depends on tank configuration: for the low-fill slender tank in one recent case study, API 650 design equations underestimated base moment by about 27 percent (Yang and Anderson 2026).

Ground deformation. A corridor-scale analysis of the initial seismic vulnerability assessments found them deterministic, facility-specific, and methodologically inconsistent in subsurface characterization, ground-motion selection, and deformation estimation, and found that additional cone penetration testing would improve confidence where exploration is sparse (Tijerina Esquino 2026). The constraint is comparability more than the number of facilities assessed. Standardizing assumptions across existing assessments could improve comparability before any new collection. Targeted investigations would be most useful where alternative soil interpretations materially change predicted deformation at tanks, piping, or containment. A modest number of such investigations may improve the release model more than years of administrative records, although they add no observations of tank failure.

Fragility and loss of containment. Empirical fragility functions are the starting point for translating deformation into damage. A database of more than 400 on-grade steel tanks from nine earthquakes showed differences by height-to-diameter ratio and by fill level large enough to warrant separate curves (O'Rourke and So 2000). Those observations come from other earthquakes. They do not relate Cascadia ground deformation to specific failure modes at the Hub, where most tanks predate modern seismic codes and are unlikely to be anchored (Dusicka and Norton 2019). A fragility function also gives the probability of a damage state, not the volume released. A piping leak and a shell rupture can carry similar damage probabilities and release very different fractions of inventory, which is why seismic risk analyses of storage facilities link fragility to separate loss-of-containment and consequence models (Fabbrocino et al. 2005). Numerical analysis of archetype tanks defined by size, roof type, structure, and soil could supplement the empirical functions (Dusicka and Norton 2019). The number of archetypes would depend on variation in design, foundation conditions, and failure mechanisms, not on the number of certificates.

For example, two diameter classes (Dusicka and Norton 2019), two roof types, anchorage, and fill above or below half define 16 combinations before soil conditions are added, so the archetype set likely numbers in the tens rather than the hundreds. A corridor-scale deformation study of the Hub analyzed three representative cross sections under five Cascadia ground motions (Tijerina Esquino 2026), which indicates the scale of a single targeted analysis.

Scenario standard. Tanks exposed to the same shaking and deformation do not fail independently, so a mature release model would evaluate every tank at a terminal under common earthquake scenarios. Two decisions would remain for DEQ: which scenarios to compare, and how to read uncertain results. The largest simulated release, an expected release, and a high percentile can produce very different quantities, and a probability-weighted average is not the largest credible release around which a financial assurance requirement is designed. European guidance on Natech risk management treats explicit scenario identification and consequence modeling as steps beyond hazard information (Necci and Krausmann 2022). A modeling protocol and decision rule are therefore a task for the first review, and the correlated-share expression in Appendix B is retained only as a screening sensitivity. Any credit for modeled mitigation would also need to be reconciled with the largest-tank floor.

Containment and pathways. Containment and pathway data change the consequences of a modeled release, not its volume. Secondary containment can reduce the volume reaching the river without reducing the volume leaving a tank, so the model would track gross release, retained volume, and volume reaching receptors separately. Relevant fields include containment capacity and seismic stability, drainage connections, site elevation, and hydraulic connection to surface water. Receptors can be described with the Environmental Sensitivity Index structure for shoreline habitat, biological resources, and human use (NOAA 2019), which identifies exposure but assigns no monetary damages.

Unit cost. The unit cost faces the opposite constraint. Its inputs are the costs of actual releases, and the regulated population will generate few. Of 242 storage tank accidents compiled worldwide over four decades, the authors identify only four earthquakes that produced catastrophic spills or fires (Chang and Lin 2006). Two onshore facility incidents since 1990 have exceeded the federal limit of liability, against more than 5,600 that did not (US Coast Guard 2026). Cost records also mature slowly; the natural resource damage claim for the 2006 CITGO Lake Charles release was resolved in 2021 (NOAA 2021). The available compilations are small and heterogeneous. The national settlement compilation contains 88 assessed (Hodgdon and Industrial Economics 2023), and the California operator survey contains 133 mostly small inland releases, none of which reached flowing water (Catalyst Environmental Solutions et al. 2019).

The number of observations needed to differentiate costs depends on dispersion, effect size, and model structure. Per-barrel costs in the California survey run from $35 at the 10th percentile to $6,600 at the 90th (Catalyst Environmental Solutions et al. 2019), which implies a standard deviation of about 2 in natural logarithms. Taking that dispersion as an illustrative assumption, a two-sample comparison at 80 percent power and 5 percent significance would need about 50 independent observations per class to detect a threefold difference, 130 for a

twofold difference, and 380 for a 1.5-fold difference, before any adjustment for comparisons across the sixteen classes in Table B1. A pooled model that borrows information across product, pathway, and receptor could require fewer observations but would depend more on its assumptions where data are thin. Because the survey describes small inland releases rather than catastrophic terminal releases, these figures indicate the scale of the problem and do not set a sample requirement. Obtaining observations with comparable definitions and complete cost components is a separate obstacle from reaching any count.

The unit cost therefore depends on pooled evidence to which Oregon contributes but which it cannot generate alone, including federal claims data, natural resource damage settlements, DEQ cost recovery for spills of all sizes, and the rate review California must complete by June 30, 2027. Recording DEQ expenditures on every spill by cost category, and separating costs incurred, amounts recovered, and outstanding liabilities, would make Oregon observations usable when they occur. It is recommended that DEQ build the unit cost from pooled evidence rather than wait for Oregon incident data to calibrate it.

Fire. Earthquake-triggered releases can involve simultaneous ignition, impaired firefighting, and escalation across equipment and facilities (Krausmann et al. 2017). Public fire costs therefore depend on exposed infrastructure, suppression capacity, and duration more than on barrels released. A mature framework would estimate in-scope public costs for each scenario as the sum of response, natural resource damage, fire, and other public cost components, and would divide that sum by the scenario release to obtain an effective unit cost only where a comparison with the initial framework requires one. This form allows multi-terminal escalation and loss of firefighting capacity to be evaluated directly. It is recommended that fire be estimated as a scenario cost component rather than as a fixed per-barrel rate.

Implications for the first review. If the first evaluation follows the first renewal round, the 2027 application cycle and the renewal will give DEQ two reporting snapshots and up to three years of operating records. Both depend on the initial rule, since operating records exist only if the 2027 rule requires fill-level reporting, common tank identifiers, and the Table 12 fields. Under a common reporting specification, these could support comparable facility inventories, documented operating limits, updated mitigation records, preliminary pathway classes, and better information on financial assurance mechanisms. Targeted engineering analysis could add comparable conditional release estimates where current assessments are incomplete or inconsistent. Those estimates would remain model-based, since validating fragility functions requires damage observations that only an earthquake produces. The same period could not produce a statistically calibrated schedule of unit costs or a general monetary rate for fire.

The maximum also limits what better data can change. At $12,500 per barrel it binds at 24,000 barrels (Figure 5), so for most terminals a refined release estimate or rate alters the calculated amount and not the required one. By 2030, the principal value of scenario modeling is to inform the review of the maximum, residual funding, and correlated failure of financial assurance mechanisms, rather than to differentiate individual certificates. The scale of administrative data collection is modest, while the scale of analytical development is substantial, and differentiation beyond the quantity term can proceed only as far as engineering and cost evidence supports it.

Implementation Timeline

Table 15 orders these steps by statutory date and states the condition each depends on. Certificates are renewed every three years (§4(2)(g)), so with applications due by March 31, 2027 (§8), the first renewals arrive in 2030, after the date on which evaluation of the maximum may begin (§7). It is therefore recommended that the first evaluation be scheduled after the first renewal round so it can draw on two reporting snapshots. Steps beyond 2030 are framed as conditions rather than dates, because they depend on engineering protocols and pooled cost evidence that the program does not control.

Table 15: Implementation Timeline for the Financial Assurance Framework

Milestone	Basis	What becomes possible	Condition
Initial rule; applications due by March 31, 2027	HB 4100 §8; §4(2)(f)	Table 12 reporting fields, fill-level records, common tank identifiers, category-level cost recording, and a §4(5) update schedule	Requirements written into the initial rule
California rate study, June 30, 2027	SB 237 (OSPR staff, interview, June 30, 2026)	Current comparator cost evidence and rate structure	Study completed and released
DEQ reports to the legislature, September 15, 2027 and each even-numbered year	HB 4100 §§5–6	First uncapped totals; progress on reporting and verification	None
First renewals, 2030	§4(2)(g)(A)	Second reporting snapshot; up to three years of operating records	Certificates issued in 2027
First evaluation of the maximum, after the first renewals	§7; §4(4)(b)	Review of the maximum and indexation; adoption of a seismic modeling protocol and decision rule	Comparable inputs from two snapshots
Second evaluation, 2033	§4(4)(b); ORS 468B.513(2)(i)	Earliest scenario-based design quantity, applied through mitigation plan updates	Protocol adopted at the first evaluation; updates based on new findings limited to once every three years
Unit-cost differentiation	§4(5)	Class-specific rates or scenario cost components	Pooled evidence shows class differences that explain covered costs; no fixed date
Residual funding layer	Legislation	Pooled fund behind certificates	Earliest legislative session after DEQ's 2028 report

Note: Section references are to HB 4100 (2026) unless otherwise stated. ORS 468B.513(2)(i) is as amended by section 9 of HB 4100.

Each workstream has a different owner. Routine reporting falls to operators under the certificate rule. Targeted engineering falls to operators through third-party analysis reviewed by DEQ, consistent with the treatment of alternative design quantities in Section 7B, and to research partners for work such as archetype fragility, which current Portland State University research identifies as a next step (Yang and Anderson 2026). External research falls to DEQ in coordination with federal agencies and comparator states. HB 4100 extends the Seismic Risk Mitigation Fund fee to the costs of carrying out ORS 468B.510 to 468B.525 (§9) and raises DEQ's expenditure limitation by $175,162 for the biennium ending June 30, 2027 (§11). That allocation supports administration of the first cycle, while the engineering and pooled-cost workstreams would require dedicated fee revenue, grants, or research partnerships.

8. Conclusions and Recommendations

Summary of Findings

HB 4100 directs the EQC to set reasonable minimum amounts of financial assurance on the basis of the six criteria in §4(2)(a). Section 3(5) limits the assured liability to costs and damages incurred by public entities, including response and cleanup, fire damage, and natural resource damage assessment and restoration. The value of a certificate also depends on whether its instruments respond when a claim arises, so coverage terms and access to funds matter as much as the stated amount.

No Oregon incident approaches the scale of a Cascadia release at the CEI Hub, which the consequence assessment projects at 2.25 million to 4.61 million barrels. Oregon cases identify the drivers of cost: receiving environment, product persistence, fire, infrastructure involvement, and the duration of contamination. National cases supply observations at terminal scale, and natural resource damage settlements alone average about $8,350 per barrel. Documented earthquake-induced releases do not report costs that separate spill response, fire, and natural resource damages from broader earthquake losses, and none of the per-barrel figures reviewed prices fire, for which the literature offers no settled valuation method. The projected Hub estimates are therefore lower bounds for the §3(5) liability.

The $12,500 rate and $300 million maximum descend from California rulemakings of the early 1990s. The rate predates California's principal cost study, survived a recommendation to raise it, and has never been indexed. Washington retained it in 2024 on grounds of market capacity and did not find that it reflects contemporary costs. Alaska's capacity-based rate yields amounts 17 to more than 200 times smaller than the uncapped Washington calculation, but it has no identified empirical basis and operates under a much lower ceiling.

Environmental sensitivity is already embedded in every unit cost reviewed, so it enters the calculation more coherently as a class that selects a rate than as a multiplier. Commercial pollution insurance for onshore facilities has a practicable limit of $200 million, and facilities at the $300 million maximum combine insurance with self-insurance or other mechanisms. Earthquake exclusions, gaps between layers, and limits shared across facilities can reduce the amount accessible after a correlated release.

Chapter 7 reduced the six criteria to a design quantity, Q, and a unit cost, U, with commercial availability as a feasibility test and the statutory maximum as a ceiling. Under the WCS basis, the maximum binds at twelve of thirteen reporting terminals at any rate above $5,172 per barrel. At half of total capacity, all thirteen reach it at $10,000 per barrel or less (Figure 3). The choice

among rates with West Coast precedent therefore changes the required amount at one terminal at most. The uncapped calculation of roughly $18.5 billion, against $3.85 billion required, indicates the gap between the regulatory calculation and certificate limits, not a modeled estimate of losses from one Cascadia earthquake. The 2027 application cycle and first renewal can improve the quantity term and inform the maximum review, but the unit cost depends on pooled national evidence and fire on scenario-specific consequence estimates.

Recommendations

The recommendations below translate these findings into a requirement that the EQC can adopt in 2027 with the information presently available, while preserving a path toward more Oregon-specific treatment as the evidence develops.

- **Initial calculation.** It is recommended that the statutory criteria inform the two inputs of a single calculation, a design spill quantity multiplied by a unit cost per barrel and subject to the $300 million statutory maximum, rather than operate as separately weighted coefficients.
- **Design quantity.** It is recommended that the initial quantity be the verified worst-case spill volume, not less than the full capacity of the largest in-service tank. Total storage capacity is a weaker basis because no cost rate is expressed per barrel of capacity.
- **Unit cost and maximum.** It is recommended that the unit cost be no lower than $12,500 per barrel. The evidence provides no affirmative support for a lower rate, and several cost indicators exceed it. The $12,500 benchmark rests on regional consistency and administrability rather than an Oregon-specific cost estimate, and at that rate the $300 million maximum determines the requirement for twelve of the thirteen terminals with a reported WCS.
- **Calculated and required amounts.** It is recommended that each certificate report both the required and the calculated amounts. Across the reporting terminals, the calculated amount exceeds the required amount by approximately $14.7 billion. That difference is neither assured liability nor a modeled estimate of earthquake losses, but it indicates the exposure excluded by the maximum and informs DEQ's evaluation.
- **Shared data with the seismic program.** It is recommended that certificate applications and seismic vulnerability assessments share common tank identifiers and fields. Shared fields would allow verified mitigation, such as an enforceable fill limit, to be reflected in the design quantity.
- **Reporting and review schedule.** It is recommended that the initial rule require the Table 12 fields, fill-level records, and a common tank identifier, and that it set the §4(5) update schedule to coincide with renewals and the three-year evaluation of the maximum, with the first evaluation scheduled after the first renewal round (Table 15).

- **Mechanisms.** It is recommended that DEQ review earthquake exclusions, continuity across layers, limits shared among facilities, and access to funds before accepting specific instruments.
- **Nonpetroleum inventory.** It is recommended that the standard rate apply provisionally to materials whose dominant hazard is not an oil spill until facility-specific alternative amounts can be developed (WAC 173-187-120). Appendix Table B5 sets out possible treatment by material.
- **Differentiation and future review.** It is recommended that the post-2030 review consider pathway, product, and receptor classes, using reporting fields collected from 2027 and outputs from the seismic vulnerability assessments and risk mitigation implementation plans (ORS 468B.510–.513). Appendix B shows how such distinctions could later be tested, but the present Oregon evidence does not support calibrated class-specific rates, and correlated-release quantities await consistent tank-level seismic outputs and a defined scenario standard.
- **Indexation.** If DEQ considers an inflation adjustment, it is recommended that the same index, using the same Oregon base year, be applied to both the maximum and the unit cost rate, as this preserves the design quantity at which the maximum binds.
- **Residual exposure.** It is recommended that DEQ evaluate the residual layer separately from the certificate. Facility-level assurance cannot reach calculated exposure at most terminals, and Oregon has no comparably capitalized public backstop. Uncapped amounts recorded in the first certificate cycle would provide an empirical basis for later evaluating the residual layer, which other states address through industry-funded response funds.

The three stages developed in Chapter 7 use the same underlying calculation; what changes is the quality of the evidence behind its inputs. Adopting the Washington calculation as the initial 2027 framework provides an administrable implementation of the statutory criteria without precluding later refinement as Oregon-specific quantity, cost, and consequence evidence becomes available.

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10. Appendices

10A. Appendix A: Industry-Funded Response Funds in Other States

This appendix describes the state programs summarized in Table 8. The per-barrel figures are fund contribution rates and are not comparable with the per-barrel requirements examined in Chapter 4.

Virginia. Operators of aboveground storage tank facilities must demonstrate five cents per gallon of aggregate aboveground storage capacity, or $2.10 per barrel, up to $1 million (9VAC25-640-50). The requirement is based on capacity and is closer in concept to Alaska's than to a transfer fee. The Virginia Petroleum Storage Tank Fund provides a second layer for eligible response and cleanup costs, and responsible-party liability continues beyond the fund's share. The low facility-level requirement therefore reflects the pooled resources behind it and not an estimate of spill cost.

Maine. The Ground and Surface Waters Clean-up and Response Fund is a nonlapsing revolving fund with a statutory balance limit of $18.5 million. It may be used for administration, removal and cleanup of oil discharges, restoration of water supplies, and qualifying third-party damages (38 M.R.S. § 551). Base assessments on petroleum entering the state are $0.41 per barrel of gasoline, $0.22 for most refined products, $0.07 for No. 6 fuel oil, and $0.03 for crude oil and liquid asphalt. Surcharges apply when the balance falls to $6 million, and effective November 1, 2025 they raised total assessments to $0.61 for gasoline and $0.32 for most other refined products (Maine Department of Environmental Protection 2025).

Massachusetts. The Oil Spill Prevention and Response Trust Fund is financed by an assessment of $0.05 per barrel on petroleum products received at marine terminals by vessel from outside the state (Massachusetts Department of Revenue n.d.). Established after the 2003 Bouchard No. 120 spill in Buzzards Bay, the fund may pay for response and containment, natural resource damage assessment and restoration, wildlife rehabilitation, municipal response training and equipment, and navigational safety (Mass. Gen. Laws ch. 21M, § 8; Massachusetts Executive Office of Energy and Environmental Affairs 2026). It can finance response where a responsible party is absent, unable, or unwilling to act and federal funds cannot be accessed quickly, and the Attorney General then recovers the expenditure (§ 8(f), (h)). The fund thus addresses the timing of payment as well as ultimate solvency.

Texas. The Coastal Protection Fee is $0.013 per barrel of crude oil or condensate transferred at marine terminals. Collection is suspended when the unencumbered fund balance exceeds $20 million and resumes below $10 million, and the rate rises to $0.04 if a discharge exceeding

100,000 gallons threatens to deplete the fund (Tex. Nat. Res. Code §§ 40.154–.155). The fee was suspended effective May 1, 2026 after the fund reached its threshold (Texas Comptroller of Public Accounts 2026).

Louisiana. The Oil Spill Contingency Fund covers removal costs, damages, natural resource assessment and restoration, and response and prevention activities (La. R.S. 30:2484). Its fee is $0.0025 per barrel of crude oil received by a refinery. The fee doubles when the balance falls below $5 million after a discharge exceeding 100,000 gallons or specified qualifying expenditures, and it remains elevated until the balance reaches $7 million (La. R.S. 30:2485).

Florida. The Coastal Protection Trust Fund is supported by an excise tax of $0.02 per barrel on covered pollutants. Collection ceases when the fund reaches $50 million and resumes at $40 million. After a catastrophic discharge the rate may rise to $0.10 until the fund is restored, and a $0.05 rate applies while proven claims remain unpaid, and the balance is below $20 million (Fla. Stat. § 206.9935(1)). For moderate or major discharges, a claimant must generally present the claim to the responsible party first and may turn to the fund if it remains unpaid after 90 days (Fla. Stat. § 376.123). The fund thus supplies public liquidity within a continuing polluter-pays structure.

New Jersey. The Spill Compensation and Control Tax is $0.023 per barrel of petroleum products and 1.53 percent of fair market value for most other hazardous substances (New Jersey Division of Taxation 2026). The fund compensates parties injured by hazardous substance discharges while preserving responsible-party liability for cleanup and removal (New Jersey Department of Environmental Protection 2024). Because its base extends beyond petroleum, it is the closest structural comparator for the hazardous materials that HB 4100 also covers.

10B. Appendix B: Derivations Supporting the Differentiated Review

This appendix documents the derivations behind the refinements described in Chapter 7. None is proposed for the 2027 rule. The values are illustrative rulemaking sensitivities and not Oregon cost estimates.

Illustrative unit costs. The base persistence rates derive from a single cost source, and two external adjustments are then shown as sensitivities. The California cost study reports modeled total spill costs per barrel by persistence class for large spills entering marine or large river systems: $13,055 for non-persistent product, $24,183 for light persistent, $29,539 for medium persistent, and $53,582 for heavy persistent, in 2019 dollars under its high-cost approach (Catalyst Environmental Solutions et al. 2019). The study recommends high figures where the

purpose is to establish insurance coverage. The total includes third-party claims and fines, which fall outside §3(5). In the study's US West component table, response costs of $51,056 and natural resource damages of $3,267 make up 79 percent of a $68,698 total (table A-19). That share is applied to each class and convert to July 2026 dollars with the CPI-U, US city average, not seasonally adjusted, a factor of 1.306. Rounded to the nearest $500, the values for a direct water pathway are $13,500, $25,000, $30,500, and $55,500.

The indirect pathway column applies to the 0.6 ratio between California's lower- and higher-risk inland rates (14 CCR 791.7). The ratio calibrates the differential and does not define the class. The sensitive-receptor increment of $4,250 is the difference between Washington's $300 per gallon ceiling for unquantifiable natural resource damages, or $12,600 per barrel, and the national mean settlement of $8,350 (Hodgdon and Industrial Economics 2023). It is a regulatory boundary and not an estimate of the added cost of injuring a listed species.

Table B1: Illustrative Unit Costs by Product Persistence, Pathway, and Receptor Class (2026 Dollars per Barrel)

Persistence class	Example products	W1 direct, standard receptors	W1 direct, sensitive receptors	W2 indirect, standard receptors	W2 indirect, sensitive receptors
Non-persistent	Gasoline, jet fuel, kerosene	13,500	17,750	8,000	12,250
Light persistent	Diesel, No. 2 fuel oil	25,000	29,250	15,000	19,250
Medium persistent	Medium crude oil	30,500	34,750	18,500	22,750
Heavy persistent	Heavy crude, bunker fuel	55,500	59,750	33,500	37,750

Note: Example factors, not Oregon cost estimates. W2 values equal 0.6 of W1, rounded to the nearest $500; sensitive-receptor values add $4,250. Fire damage and other public costs are not priced. W3, a release with no credible pathway to surface water, has no large-volume estimate; the California operator survey reports a median of $343 and a 90th percentile of $6,600 per barrel for spills under 100 barrels. The persistence ordering reflects response and cleanup costs and does not rank total §3(5) liability; gasoline is non-persistent but a major fire hazard. The 0.6 pathway ratio and the $4,250 receptor increment are transferred regulatory values, not estimated marginal costs.

Sources: Catalyst Environmental Solutions et al. (2019); Hodgdon and Industrial Economics (2023)

This class structure is illustrative and is not a calibrated schedule. The persistence ordering is best supported for response and cleanup costs. The levels are less secure: they are modeled values from a predominantly marine database, the in-scope share is assumed constant across classes, and fire damage is not priced. The non-persistent value of $13,500 is close to $12,500, suggesting the Washington rate approximates the lowest petroleum class on a direct water pathway.

Pathway weighting. The damage zones measure how much of a release reaches water, not what a barrel costs once it arrives. They therefore enter the calculation as weights on quantity: the volume reaching water is priced at a water rate and the volume remaining on land at a land

rate. The consequence assessment places 40.8 million of 94.6 million gallons in the in-water and potentially-in-water zones under its low scenario and 82.5 million of 193.7 million under its high scenario, a water share of 43.1 and 42.6 percent (ECONorthwest 2022). The land rate is weaker; the closest large-volume observation is the Murphy Oil release, at about $2,800 per barrel as settled and $5,000 in 2026 dollars (Table 6).

Table B2: Illustrative Two-Term Calculation Using Oregon Damage-Zone Weights

Parameter	Value	Basis
Share of modeled release reaching water	43 percent	ECONorthwest (2022); 43.1 percent low scenario, 42.6 percent high
Unit cost, barrels reaching water (light persistent)	$25,000	Table B1
Unit cost, barrels remaining on land	$2,800 to $5,000	Murphy Oil, as settled and in 2026 dollars (Table 6)
Blended unit cost at the modeled water share	$12,350 to $13,600	Calculated
Implied differential relative to the water rate	0.49 to 0.54	Calculated
California inland ratio, for comparison	0.60	14 CCR 791.7

Note: Illustrative rulemaking sensitivities, not Oregon cost estimates.

Sources: ECONorthwest (2022); 14 CCR 791.7.

The blended rate is an illustrative consistency check, not an independent validation of $12,500. The water proportion is a facility-level, volume-weighted parameter from a modeled scenario and not a property of any tank; a tank beside the river has a water share near one, whatever the facility average. The approach is also consistent with federal spill-cost modeling that treats spill location and receiving-environment characteristics as determinants of cost alongside release volume (Pipeline and Hazardous Materials Safety Administration 2023). The land rate rests on a single crude oil release, and applying it across persistence classes is not supported.

Effect on required amounts. A rate class changes a requirement only below the quantity at which the maximum binds for that rate (Figure 5). Table B3 applies the schedule to a 10,000-barrel design quantity, which is small enough for the rate to control in every class but the heaviest.

Table B3: Illustrative Required Amounts for a 10,000-Barrel Design Quantity

Case	Rate per barrel	Calculated amount	Required amount
Uniform initial rate	$12,500	$125.0M	$125.0M
Non-persistent, W1 direct, standard receptors	$13,500	$135.0M	$135.0M
Light persistent, W2 indirect, standard receptors	$15,000	$150.0M	$150.0M
Light persistent, W1 direct, standard receptors	$25,000	$250.0M	$250.0M
Light persistent, W1 direct, sensitive receptors	$29,250	$292.5M	$292.5M
Heavy persistent, W1 direct, standard receptors	$55,500	$555.0M	$300.0M

Note: Illustrative rulemaking sensitivities, not Oregon cost estimates.

Correlated release quantity. A standardized correlated quantity adds to the largest tank a share of the other capacity exposed to the same failure mechanism: $Q = V$ (largest tank) + $\alpha \times V$ (correlated capacity). The coefficient α is the modeled fraction of the correlated capacity released after accounting for tank fragility, fill level, piping failure, secondary containment, and verified mitigation. No value can be fixed until assessments report those inputs consistently. Table B4 shows the effect for a terminal below the 24,000-barrel binding quantity. The coefficient changes the required amount only until the terminal reaches the maximum, and above that point it changes the calculated amount alone. The expression is a screening sensitivity. Where an assessment models release under common scenarios, the coefficient can be dropped and the design quantity selected by the decision rule described in Chapter 7.

Table B4: Illustrative Correlated-Release Sensitivity for a Terminal below the Binding Quantity

α	Largest tank (bbl)	Other correlated capacity (bbl)	Design quantity (bbl)	Calculated at $12,500 ($M)	Required at $300M maximum ($M)
0.00	15,000	20,000	15,000	187.5	187.5
0.25	15,000	20,000	20,000	250.0	250.0
0.50	15,000	20,000	25,000	312.5	300.0
1.00	15,000	20,000	35,000	437.5	300.0

Note: These are not Oregon cost estimates. Capacities and coefficients are hypothetical and are not findings for an Oregon terminal.

Inventory other than petroleum. A petroleum value transfers to another material only for the cost component in which that material behaves like the petroleum class. Table B5 orders the options as direct equivalence, conservative analogue, and engineered estimate.

Table B5: Treatment of Inventory Other than Petroleum

Material	Treatment	Basis
Renewable diesel	Light persistent class	Direct equivalence where the product meets the ASTM D975 diesel specification
Drop-in aviation fuel	Non-persistent class	Direct equivalence after certification to the jet fuel specification
Biodiesel (B100)	Light persistent class, with no downward credit	Conservative analogue; a distinct ester product under ASTM D6751
Ethanol	Non-persistent class as an interim screen	Water soluble and flammable; the fire component is unpriced
Asphalt	Heavy persistent class	Conservative analogue; the product solidifies and requires mechanical removal
Liquefied natural gas	Engineered estimate through the alternative-amount procedure	Thermal radiation and vapor dispersion modeling (49 CFR 193.2057; 49 CFR 193.2059)

Note: Illustrative rulemaking sensitivities, not Oregon cost estimates. This is not a recommendation of flat tiers by container size; New Jersey's tiers for hazardous substances end at $4 million per occurrence, far below the consequences of a release at a terminal of this scale (N.J.A.C. 7:1E-4.4).

Data specification. The fields in Table 12 draw on work the seismic program already requires under ORS 468B.510 and ORS 468B.513. It is recommended that certificates, contingency plans, seismic assessments, and mitigation plans share one tank identifier. Tanks in a shared dike are treated as one release scenario only where an assessment models them failing together. Mitigation enters as a change to the physical scenario once installed and verified, not as a discount to the dollar amount.

10C. Appendix C: Interview Methods

This report supplements the review of statutes, rules, and rulemaking files with semi-structured interviews of staff who administer financial responsibility programs in California and Alaska. Oregon DEQ staff led the interviews, with members of the project team participating, using a common protocol reviewed in advance by the FTSS program. The protocol covered the mechanisms accepted and those most used, the basis for minimum and maximum amounts and the process for changing them, enforcement authority and practice, and other jurisdictions or sources the program had consulted. Washington's program was reviewed through Ecology's published rulemaking file.