Chapter 600: OIL DISCHARGE PREVENTION AND POLLUTION CONTROL RULES FOR MARINE OIL TERMINALS, TRANSPORTATION PIPELINES AND VESSELS

TABLE OF CONTENTS

1. Preamble 1

2. Definitions 1

3. Applicability 8

A. Oil Terminal Facilities 8

B. Intrastate Pipelines 8

C. Vessels 8

4. Oil Discharges 8

A. Oil Discharge Reporting Procedure 8

B. Vessel Cleanup 10

5. Vessel to Vessel Transfer Areas and Hussey Sound Limitation 10

A. Hussey Sound Limitation 10

B. Vessel Transfers While at Anchor 10

6. Siting Requirements 10

A. New Land Based Oil Terminal Facilities 10

B. Existing Land Based Oil Terminal Facilities 11

7. New Land Based Oil Terminal Facility Minimum Design Standards, Construction Standards and Related Measures 12

A. Prior Approval 12

B. Aboveground Oil Storage Tanks 12

C. Piping, Valves and Pumps 13

D. Tank Secondary Containment 14

E. Facility Drainage Systems 16

F. Tank Truck and Tank Car Loading and Unloading 18

G. Fire Prevention 18

H. Physical Security 18

I. Dock Facility 19

J. Shop-Fabricated Aboveground Storage Tanks and Appurtenancess 19

K. Natural Hazard Risk Assessment 21

8. Existing Land Based Oil Terminal Facility Minimum Design Standards, Construction Standards and Related Measures 22

A. Notification of Work 22

B. Aboveground Oil Storage Tanks 22

C. Piping, Valves and Pumps 24

D. Tank Secondary Containment 25

E. Leak Monitoring and Detection 26

F. Existing Tank Truck and Tank Car Loading and Unloading Spill Containment 26

G. Reopening a Closed Facility 27

H. Other Requirements 27

I. Shop-Fabricated Tanks 27

9. Standard Operating Procedures 27

A. Transfers Between Land Based Oil Terminal Facilities and Vessels 27

B. Booming of Vessels 33

C. Land Based Oil Terminal Facilities 34

10. Intrastate Pipelines 39

11. Land Based Oil Terminal Facility Staff Training 39

12. Non-Operating Tanks and Facilities 40

A. Facility Lockout 40

B. Temporarily Out of Service 40

C. Tanks Out of Service 41

D. Facility Closure 41

E. Owner Responsibility 44

13. Licensing 44

A. Oil Terminal Facility License 44

B. Probable Cost Estimate and Preliminary Facility Closure Plan 44

C. Liability Insurance and Documentation 44

APPENDIX A: Specifications and Requirements for Vertical Ground Water Monitoring Wells 46

APPENDIX B:Oil Sampling and Storage Procedure 48

APPENDIX C:List of Reference Material 49

APPENDIX D:Natural Hazards, Climate Change, and Flood Risk Reference Material 52

Chapter 600: OIL DISCHARGE PREVENTION AND POLLUTION CONTROL RULES FOR MARINE OIL TERMINALS, TRANSPORTATION PIPELINES AND VESSELS

**SUMMARY**: This Chapter sets forth minimum design and operating requirements for marine oil terminals and intrastate pipelines. Separate sections are included for vessel operation and navigation, siting requirements, design and construction standards for new and existing marine oil terminal facilities, staff training and safety, and closure of tanks and facilities.

**1. Preamble.**  It is the purpose of this Chapter, consistent with legislative policy, to provide necessary oil spill prevention and control rules for all facilities and operations associated with marine oil terminals, intrastate pipelines and vessels, so as to prevent discharges of oil to the waters and lands of the State, to prevent other discharges of oil prohibited under *Oil Discharge and Prevention Control,* 38 M.R.S. §543, and to ensure proper closure of terminal facilities.

NOTE: This Chapter incorporates by reference certain industry codes and standards. Appendix C lists those codes and standards that are incorporated by reference and the specific amended date for each reference.

**2. Definitions.** The following terms as used in this Chapter have the following meanings:

**A. 100-year floodplain.** "100-year floodplain" means the area which has a 1% or greater annual chance (1 in 100-year probability) of being inundated by a flood. 100-year floodplains are designated on the Federal Emergency Management Agency’s (FEMA) Flood Insurance Rate Maps (FIRM) or Flood Hazard Boundary Maps, or determined by the flood of record, or in the absence of these, by soil types identified as recent floodplain soils.

**B. 24-hour storm.** “24-hour storm” means a precipitation event with a specific probability of being equaled or exceeded during any twenty-four hour period during any given year, for example 4% (for a 25 year) or a 1% (for a 100 year).

**C. Abandoned.** “Abandoned” means a facility that no longer has an active marine oil facility license but that did not go through a closure process pursuant to Section (12)(D).

**D. Aboveground oil storage tank.** "Aboveground oil storage tank", also referred to as a "tank", means any stationary container, of which more than 90% is above the surface of the ground and that is used or intended to be used for the storage or supply of oil. Included in this definition are any tanks situated upon or above the surface of a floor in such a manner that they can be readily inspected. For the purpose of this Chapter, aboveground oil storage tanks do not include aboveground propane storage tanks.

**E.** **Adaptation. “**Adaptation” means taking actions that reduce the harmful effects from natural hazards to people and the environment.

**F. Alter.** "Alter" means any enlargement, upgrading, repair or removal of a storage tank system or any change in the configuration of any piping, tanks, or diking or the replacement of any tank. The term "alteration" has the same meaning.

**G. Approved.** "Approved" means approved by the Commissioner or the Commissioner's designee in writing or orally with written confirmation as soon as practicable.

**H. Bulk.** "Bulk" means material in any quantity that is shipped, stored, or handled without benefit of package, label, mark or count and carried in integral or fixed independent tanks.

**I. Bulk oil or oil as cargo.** "Bulk oil" or oil as "cargo" means any oil not carried as fuel for bunkering or recovered incidental to oil spill response activities.

**J. Bunkering.** “Bunkering” means the act of supplying oil to a ship for its own use as fuel.

**K. Cathodically protected.** "Cathodically protected" means the use of a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

NOTE: For example, a tank system can be protected against corrosion through the application of either a galvanic or an impressed current cathodic protection system.

**L. Cathodic protection assessment.** "Cathodic protection assessment" means an analysis to determine the need for cathodic protection in order to protect a tank bottom from corrosion. This assessment must be based upon a corrosion survey that includes soil analysis and resistivity measurements, operating records, corrosion history, corrosion allowance, prior test results with similar tank systems in similar environments and current and future plans for the tank.

**M. Cathodic protection tester.** "Cathodic protection tester" means a person certified as a Cathodic Protection Tester, Cathodic Protection Technician, Cathodic Protection Technologist, or Cathodic Protection Specialist by the National Association of Corrosion Engineers.

**N. Combustible liquid.** "Combustible liquid" means a liquid which has a flash point at or above 100° F (37.8° C). Combustible liquids are subdivided as follows:

(1) Class II liquids include those having flash points at or above 100° F (37.8° C) and below 140° F (60° C).

(2) Class III A liquids include those having flash points at or above 140° F (60° C) and below 200° F (93° C).

(3) Class III B liquids include those having flash points at or above 200° F (93° C).

**O**. **Commissioner.** "Commissioner" means the Commissioner of the Department of Environmental Protection.

**P.** **Critical infrastructure.** “Critical infrastructure” means assets, systems, and networks, whether physical or virtual, that are so vital to the operation of a facility that the incapacity or destruction of such items would have a debilitating impact on the facility, public health, safety or the environment.

**Q. Department.** "Department" means the Department of Environmental Protection composed of the Board of Environmental Protection and the Commissioner.

**R. Discharge.** "Discharge" means any spilling, leaking, pumping, pouring, emitting, escaping, emptying, or dumping into or upon any coastal waters, estuaries, tidal flats, beaches or lands adjoining the seacoast of the State, or into or upon any lake, pond, river, stream, sewer, surface water drainage, ground water or other waters of the State or any public or private water supply or onto lands adjacent to, on, or over such waters of the State.

**S. Disrepair.** "Disrepair" means when the condition of a facility does not meet the requirements for operating a facility and is in poor condition as evidenced by corroded and pitted tanks, piping, and other structures; lack of maintenance of facilities and containment structures, lack of access control, or other signs of significant neglect.

**T. Emergent vegetation.** "Emergent vegetation" means erect, rooted and herbaceous plants growing in saturated or permanently flooded areas, and that do not tolerate prolonged inundation of the entire plant.

**U. Existing aboveground oil storage tank.** "Existing aboveground oil storage tank" means an aboveground oil storage tank that was constructed before the effective date of this Chapter.

**V. Existing oil terminal facility.** "Existing oil terminal facility" means a facility that held a valid oil terminal facility license on the effective date of this Chapter.

**W. Existing oil and chemical handling areas. "**Existing oil and chemical handling areas" are the areas inside the existing footprint of a facility. The existing footprint includes the developed areas of the facility such as the dike, tank, piping, loading and unloading areas.

**X. Facility.** "Facility" or "Oil Terminal Facility" means any facility of any kind and related appurtenances, located in, on or under the surface of any land or water, including submerged lands, that is used or capable of being used for the purpose of transferring, processing or refining oil, or for the purpose of storing the same, but does not include any facility used or capable of being used to store no more than 1,500 barrels (63,000 gallons), nor any facility not engaged in the transfer of oil to or from waters of the State. A vessel is considered an oil terminal facility only in the event of a ship-to-ship transfer of oil including, but not limited to, lightering activities, but only that vessel going to or coming from the place of ship-to-ship transfer and a permanent or fixed oil terminal facility. The term does not include vessels engaged in oil spill response activities or bunkering operations.

**Y. Facility closure.** "Facility closure" means closure of a facility in a manner prescribed by Section (12)(D) of this Chapter and 38 M.R.S §542(4-B) including remediating sediment, soils, ground waters, and surface waters such that the facility site, as determined by the Department, is suitable for residential use or meets the most protective use standards practicable for the facility site.

**Z. Flammable liquid.** A "flammable liquid" is a liquid having a flash point below 100° F (37.8° C) and having a vapor pressure not exceeding 40 lbs. per sq. inch (absolute) (2,068 mm Hg) at 100° F (37.8° C). Flammable (Class I) liquids are subdivided as follows:

(1) Class IA liquids include those having flash points below 73° F (22.8° C) and having a boiling point below 100° F (37.8° C).

(2) Class IB liquids include those having flash points below 73° F (22.8° C) and having a boiling point at or above 100° F (37.8° C).

(3) Class IC liquids include those having flash points at or above 73° F (22.8° C) and below 100° F (37.8° C).

**AA.Flooding. “**Flooding” means a temporary inundation of normally dry land as a result of:

(1) The overflow of inland or tidal waters, or

(2) The unusual and rapid accumulation or runoff of surface waters from any source.

NOTE: Types of events that can cause flooding include but are not limited to: high volume rain events, ice jams, rapid snowmelts or runoff, high tide, storm surge, tsunami, dam failure or breach, and onsite development design failure.

**BB.Ground water rise.** “Ground water rise” means when the water table in rock and soil increases in elevation.

**CC.Handling.** "Handling" means the storing, transferring, collecting, separating, salvaging, processing, reducing, recovering, incinerating, treating, disposing, or transporting of oil.

**DD.Highest astronomical tide.** “Highest astronomical tide” means the elevation of the highest predicted astronomical tide for a specific tide station over the National Tidal Datum Epoch, or NTDE.

NOTE: The NTDE is a specific 19-year period adopted by the National Ocean Service as the official time segment over which tide observations are taken. This range of time is used to obtain mean values, such as mean low water level. It is necessary for standardization because of variations in tides from year to year. If you have general questions about the National Tidal Datum Epoch, email tide.predictions@noaa.gov.

**EE.Internal tank bottom liner.** "Internal tank bottom liner" means an internal, bonded barrier on the top side of a tank’s internal steel floor as described in American Petroleum Institute (API) 652, Recommended Practice, Lining of Aboveground Storage Tank Bottoms.

**FF.Intrastate pipeline.** "Intrastate pipeline" means a pipeline or that part of a pipeline that is used in the transportation of oil used in commerce within the State.

**GG.Lightering.** “Lightering” means to transfer oil cargo between vessels of different sizes, such as a barge and an oil tanker, to reduce the larger vessel's draft in order to enter port facilities.

**HH.Monitoring well.** "Monitoring well" means a dug or drilled, cased well or other device used to detect oil in ground water that can be used for detecting the presence of at least one-eighth of an inch of oil.

**II. Natural hazard.** “Natural hazard” means any natural phenomenon that exposes an area or person to risk of property damage, loss of life, or environmental degradation. In Maine, coastal and inland natural hazards may include, but are not limited to, severe summer and winter weather events, ice jams, erosion, mass wasting, drought, wildfires, flooding, and ground water rise.

**JJ. New oil terminal facility.** "New oil terminal facility" means an oil terminal facility whose application for a license is received after the effective date of this Chapter.

**KK.New aboveground oil storage tank.** "New aboveground oil storage tank" means an aboveground oil storage tank permitted for construction after the effective date of this Chapter.

**LL. Oil.** "Oil" means oil, petroleum products and their by-products of any kind and in any form including, but not limited to, petroleum, fuel oil, sludge, oil refuse, oil mixed with other wastes, liquid asphalt, bunker fuel, crude oils, oil additives, and all other liquid hydrocarbons regardless of specific gravity. Oil does not include liquid natural gas.

**MM.Oil/water separator.** "Oil/water separator" means a device used to separate and remove oil and oily wastes from oil and water mixtures.

**NN.Owner or operator.** "Owner or operator" means any person owning or operating an oil terminal facility or pipeline, whether by lease, contract or any other form of agreement or a person in control of, or having responsibility for, the daily operation of an oil storage facility.

**OO.Owner.** "Owner" means the person who alone or in conjunction with others owns an oil terminal facility.

**PP.Person.** "Person" means any natural person, firm, association, partnership, corporation, trust, the State of Maine and any agency thereof, governmental entity, quasi-governmental entity, the United States of America and any agency thereof and any other legal entity.

**QQ.Pipeline.** "Pipeline" means any part of an intrastate oil line including line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein.

**RR.Piping.** "Piping" means the piping and accessories within a facility used for the conveyance of oil between tanks or between tanks and loading and unloading points.

**SS.Piping run.** A "piping run" means the piping between any of the following items: bolted flange, valve, or pump.

**TT.Piping tightness test.** "Piping tightness test" means a method to test the integrity of piping systems. The integrity of piping systems must be assured by one or more of the following: pressure testing, volumetric testing or internal inspection devices designed to verify the structural integrity of the pipe by measuring pipe wall thickness and indicating geometric irregularities.

**UU.Primary containment.** “Primary containment” means a device, tank or container that is designed to be in direct contact with and to enclose a material or waste so as to reduce the risk of release.

**VV.Private drinking water supply.** "Private drinking water supply" means any dug, drilled or other type of well or spring or other source of water used for human or livestock consumption that is not a public water supply.

**WW.Public drinking water supply.** "Public drinking water supply" has the same meaning as "public water system" in *Water for Human Consumption,* 22 M.R.S. §2601(8).

**XX.Reconstructed tank.** "Reconstructed tank" means any tank that has been dismantled, relocated to a new location and reassembled.

**YY.Related appurtenances.** "Related appurtenances" means all structures related to the operation of an oil terminal facility including but not limited to pumps, valves, piping, loading racks and secondary containment. The term does not include day tanks that are not connected to pipelines, racks, or storage tanks which receive oil from marine transport vessels. For example, tanks supplying start-up fuel for electrical generation that are not connected to the marine oil terminal portions of the facility through pipelines or other means of oil transfer, and that are in no way related to the function of the oil terminal facility, are not considered "related appurtenances".

**ZZ.Release prevention barrier (RPB).** "Release prevention barrier" or “RPB” means a steel tank bottom, or any synthetic materials, clay liners and all other barriers or combination of barriers placed in the bottom of or under an aboveground storage tank that have these functions:

(1) Preventing the escape of oil, and

(2) Containing or channeling released material for leak detection.

Any RPB must be installed in accordance with API Standard 650, Welded Steel Tanks for Oil Storage.

**AAA.Resilience. “**Resilience” meansthe ability of a community, business, or the natural environment to prepare for, withstand, respond to, and recover from a hazardous event.

**BBB.Sea level rise.** “Sea level rise” means the increase in sea level, both globally and locally, primarily due to thermal expansion resulting from warming of the ocean, and increased melting of land based ice, such as glaciers and ice sheets.

**CCC.Secondary containment.** "Secondary containment" means a system installed so that any material that is discharged or has discharged from the primary containment is prevented from reaching the soil or ground water outside the system for the anticipated period necessary to detect and recover the discharged material. Such a system may include, but is not limited to, impervious liners, double-walled tanks and piping, or any other method approved by the Commissioner that is technically feasible and effective, and that meets the requirements of this Chapter.

**DDD.Significant ground water aquifer.** "Significant ground water aquifer" means a porous formation of ice-contact and glacial outwash sand and gravel or fractured bedrock, as identified by the current Maine Geological Survey maps, that contains significant recoverable quantities of water which is likely to provide drinking water supplies.

NOTE: Sand and Gravel Aquifer Maps are available from the Maine Geological Survey, Department of Agriculture, Conservation and Forestry, State House Station #22, Augusta, Maine 04333.

**EEE.Storm surge.** “Storm surge” means an abnormal rise of water level generated by a storm, measured as the height of the water above the normal predicted astronomical tide.

**FFF.Tank barge.** "Tank barge" means any tank vessel on departure from or approach to oil terminal facilities or refineries, not equipped with a means of self propulsion.

**GGG.Tank vessel.** "Tank vessel" means any vessel on departure from or approach to oil terminal facilities or refineries, that is constructed or adapted to carry, or that carries, oil in bulk as cargo or cargo residue. For the purpose of this Chapter, tank vessel does not include any vessel engaged in oil spill response activities, including response-related training.

**HHH.Temporarily out of service.** "Temporarily out of service" means a facility or portion thereof which has been out of use for 12 months or more and which meets the requirements of Section (12)(B). Facilities or tanks which are used for seasonal storage, for surcharge storage, or for standby storage, are not considered out of service.

**III.Transfer.** "Transfer" means both on-loading and off-loading between an oil terminal facility and a vessel, a vessel and another vessel, or an oil terminal facility and a vehicle.

**JJJ.Transport.** "Transport" means to convey oil in or on a vehicle or vessel, exclusive of the fuel carried for use in the vehicle. Transport also means to convey oil via a pipeline.

**KKK.Transportation pipeline.** "Transportation pipeline" means the continuous piping systems used for the intrastate conveyance of oil outside of the boundaries of an oil terminal.

**LLL.Vehicle.** "Vehicle" means a tank truck, tank car, stake truck, trailer, semi-trailer, tractor or other conveyance and appurtenances thereto designed for or capable of transporting oil, other than fuel used in the operation of that vehicle.

**MMM.Vessel.** "Vessel" means every description of watercraft or other contrivance used or capable of being used as a means of transportation on water, whether self propelled or otherwise, including, but not limited to, barges and tugs, other than a public vessel.

**NNN.Waters of the State.** "Waters of the State" means, for the purposes of this rule, any and all surface and subsurface waters that are contained within, flow through, or under or border upon this State or any portion of the State, including, but not limited to, marginal and high seas, coastal waters, estuaries, tidal flats, beaches, lake, pond, river, stream, sewer, surface water drainage, ground water and any public or private water supply, and those portions of the Atlantic Ocean within the jurisdiction of the State.

NOTE: The following acronyms and abbreviations are used in this Chapter:

(1) ANSI. American National Standards Institute

(2) API. American Petroleum Institute

(3) ASME. American Society of Mechanical Engineers

(4) ASTM. American Society of Testing and Materials

(5) CFR. Code of Federal Regulations

(6) GI. Geosynthetic Institute

(7) M.R.S. Maine Revised Statutes

(8) NACE. National Association of Corrosion Engineers

(9) NFPA. National Fire Protection Association

(10) NSF. National Sanitation Foundation

(11) PEI. Petroleum Equipment Institute

(12) POTW. Publicly Owned Treatment Works

(13) SSPC. Society for Protective Coatings

(14) STI. Steel Tank Institute

(15) UL. Underwriters Laboratories

(16) OPA 90. Oil Pollution Act of 1990, Public Law 101-380, §4202

**3. Applicability.** This Chapter applies to oil terminal facilities, intrastate pipelines, vessels licensed by the Department involved in lightering and vessels on departure from or approach to oil terminal facilities or refineries.

**A. Oil Terminal Facilities.** This Chapter applies to new or existing marine oil terminal facilities used or capable of being used to store more than 1,500 barrels of oil.

(1) Existing facilities. Existing facilities shall comply with this Chapter, unless otherwise stated in this Chapter.

(2) Responsibility. The standards set forth in this Chapter do not relieve the owner or operator from responsibility for compliance with other state and federal laws governing the safe storage and handling of oil.

**B. Intrastate Pipelines.** This Chapter applies to intrastate pipelines from terminals to remote locations and includes federal facilities.

**C. Vessels.** This Chapter applies to vessels licensed by the Department pursuant to *Oil Discharge Prevention and Pollution Control,* 38 M.R.S. §545(4) to conduct lightering operations in waters of the State, and tank vessels and tank barges on departure from or approach to oil terminal facilities or refineries licensed by the Department.

Where provisions of this Chapter differ from other regulations, the more stringent regulations apply. In the case of any conflict between this Chapter and Federal law or with a mandatory rule, regulation, or order of the Federal Government or its agencies where compliance with both is impossible, such Federal law, rule, regulation, or order governs.

**4. Oil Discharges.**

**A. Oil Discharge Reporting Procedure**. In the event of any discharge prohibited by *Oil Discharge Prevention and Pollution Control,* 38 M.R.S. §543, the person, firm or corporation responsible for the discharge shall immediately undertake to remove such discharge as required by 38 M.R.S. §548. Responsibility for removal remains with the person, firm or corporation responsible for the illegal discharge. In addition to the regular procedures, the following actions must be taken:

(1) Telephone Report. An initial telephone report of any discharge must be made to the Commissioner as soon as practicable but within two hours. The report must include:

(a) Time of discharge;

(b) Location of discharge;

(c) Type and amount of oil;

(d) Name and telephone number of person making report;

(e) Actions taken to correct or mitigate the discharge; and

(f) Other pertinent information.

(2) Written Reports. Once removal of the discharge has been completed, the person, firm or corporation responsible for the discharge shall prepare a complete written report of the occurrence and submit that report to the Commissioner within 10 days. If circumstances make a complete report impossible, a partial report must be submitted. This report must include, but not be limited to, the following information:

(a) Date, time, and place of discharge;

(b) Name of parties involved;

(c) Amount and type of oil discharged;

(d) Complete description of circumstances causing the discharge;

(e) Actions taken to correct or mitigate the discharge;

(f) Procedures, methods and precautions instituted to prevent a similar occurrence from recurring;

g) Recommendations to the Commissioner for changes in rules or operating procedures;

(h) Name and address of any person, firm or corporation that could be affected by the discharge; and

(i) In the case of any oil discharge from an intrastate pipeline, oil terminal facility, or vessel going to or coming from a facility, the person, firm or corporation responsible for the discharge shall submit a report, in writing, to the Commissioner, setting forth the amount of oil recovered.

(3) Oil Discharge Containment and Clean-up. 38 M.R.S. §548 requires any person discharging oil, or its by-products in a manner prohibited by 38 M.R.S. §543, to immediately undertake to remove the discharge to the Commissioner's satisfaction. Nothing in the rules or regulations adopted by the Board is intended to relieve any person from this responsibility. Any person who has discharged or caused to be discharged oil as prohibited by 38 M.R.S. §543 shall contain such oil and remove it as quickly and completely as possible.

(4) Delegation of Supervisory Authority. The Commissioner or the Commissioner's authorized representative shall receive reports of oil discharges and shall supervise or undertake the removal of any oil discharge, where such actions by the Commissioner are authorized under 38 M.R.S. §548, and upon the completion of removal of any discharge the Commissioner or the Commissioner's authorized representative may indicate satisfaction with such removal.

(5) Notification of the Commissioner in no way should delay the proper notification of other authorities such as local and federal agencies concerned. Protection of life and property by proper notification and action is mandatory and should be accomplished in the most expeditious manner possible.

**B. Vessel Cleanup**. Before any vessel involved in a transfer operation leaves a land based oil terminal facility, all drip pans, hoses, and other transfer equipment must be cleaned and any oil spilled on the deck, topside piping or equipment, or the exterior of the hull must be removed.

**5. Vessel to Vessel Transfer Areas and Hussey Sound Limitation.**

**A**. **Hussey Sound Limitation**. A tank ship or tank barge containing any oil cargo which is actually drawing 40 or more feet may not transit Hussey sound, Casco Bay (port of Portland) regardless of visibility, unless it would be abeam of Soldier's Ledge Buoy within one-half (½) hour of the time of high tide.

**B.** **Vessel Transfers While at Anchor**. Vessel to vessel transfers must be conducted only in anchorage areas designated by the Department.

**(**1) Vessel to Vessel Transfer Area - Casco Bay. A tank vessel anchorage area one mile square is established starting at Hussey Sound Buoy 12, Lat. 43° 42' 10" North, Long. 70° 90' 46" West (formerly Little Chebeague Island Shoal Buoy 6) thence one mile true North to Lat. 43° 43' 10" North, Long. 70° 90' 46" West; thence one mile true West to Lat. 43° 43' 10" North, Long. 70° 11' 90" West; thence one mile true South to Lat. 43° 42' 10" North, Long. 70° 11' 90" West; thence one mile true East to the point of origin.

(2) Vessel to Vessel Transfer Area - Penobscot Bay. The following tank vessel anchorage areas are established:

(a) The first area designated for vessel-to-vessel transfers of bulk oil in Penobscot Bay area is a circle 2 nautical miles in diameter with the center at Latitude 44° 24' 15" North and Longitude 68° 55' 25" West;

(b) The second area designated for vessel-to-vessel transfers of bulk oil in Penobscot Bay area is a circle of one nautical mile in diameter with the center at Latitude 44° 25' 00" North and Longitude 68° 50' 45" West;

Section (5)(B) does not apply to the transfer of fuel for a vessel's own use (bunkering operations).

**6. Siting Requirements.**

**A. New Land Based Oil Terminal Facilities.**

(1) Facility Set-Backs. Every new aboveground oil storage tank operating at pressures less than 2.5 pounds per square inch gauge must be located in accordance with NFPA 30, Flammable and Combustible Liquids Code.

Vertical tanks storing liquids must be separated in accordance with NFPA 30.

(2) Facility Location. New oil terminal facilities may not be located within the following areas:

(a) Within 3,000 feet of a surface water body intake used as a public drinking water supply;

(b) Within 600 feet of an existing private drinking water supply, except a facility's own well;

(c) Within 1,000 feet of a significant ground water aquifer; or

(d) Within 1,000 feet of an essential habitat as mapped by the Department of Inland Fisheries and Wildlife, or any refuge, park, preserve, or similar site when such site is state or federally designated.

Undeveloped areas and non-oil or non-chemical handling areas are not included in the definition of "oil terminal facilities" for the purposes of this paragraph.

(3) A new oil terminal facility located as set forth below is presumed to pose a serious threat to public health or welfare or to the environment such that a license for a facility may not be issued. The presumption applies if a facility is located:

(a) Within a 100-year floodplain, unless critical infrastructure is suitably elevated to four feet above the 100-year flood elevation to maintain continuity of operations, except for piers and piping from a pier to the terminal. Piers and piping from a pier to the terminal must be secured through an alternative means such as marine break away couplings;

(b) Within 1,000 feet of a freshwater wetland, great pond, river, stream or brook (as defined in *Natural Resources Protection Act,* 38 M.R.S. §480-B) not used as a public drinking water supply, except for piers and piping from a pier to the terminal;

(c) Within an area that is less than four feet in elevation above the highest astronomical tide (HAT) line of coastal wetlands (as defined in 38 M.R.S. §480-B) with a salt or brackish water regime (salinity equal to or greater than 0.5 parts per 1,000) that contain emergent vegetation tolerant of salt water occurring primarily in a salt water or estuarine habitat including, but not limited to, marshes and salt meadows; or

(d) Within 1,000 feet of an eel grass bed.

(4) An applicant seeking a license to establish, construct, alter, or operate a facility in a location listed in subparagraphs (3)(a)-(d) above may overcome the presumption in paragraph (3) above by persuasive evidence that either:

(a) The facility is unique in some way that allows for compliance with the intent of this Chapter through an alternative design, operation, or siting proposal which provides a level of protection equivalent to that which would be provided by the siting provision in this Chapter; or

(b) The facility environment is unique in some way such that a valuable resource will not be negatively affected by the proposed siting.

**B. Existing Land Based Oil Terminal Facilities.**

(1) Modifications to Existing Facilities. New tanks located inside the existing oil and chemical handling areas of existing facilities are not subject to the siting criteria of Section (6)(A) above. New tanks located outside the existing oil and chemical handling areas are permitted provided they comply with one of the following:

(a) They are located in compliance with the siting criteria;

(b) They are unable to meet all the siting criteria, in which case the owner or operator has demonstrated to the Department that the new tank will be constructed in the location which satisfies the greatest number of siting criteria; or

(c) The owner or operator is able to demonstrate to the Department's satisfaction that although contiguous land is available which meets the siting criteria, compliance with the siting criteria through use of this location would not be economically feasible or would create significant operational problems.

For the purposes of Sections (6)(B)(1)(b) and (c) above, land not contiguous to the existing oil and chemical handling area where the oil terminal owner or operator intends to build or land not already owned by the terminal owner or operator would not be included for consideration. A private or public right of way may not by itself be considered as dividing a property into separate noncontiguous properties.

(2) Non Operating Facilities. Existing facilities that have been abandoned, closed or that have been in disrepair for more than 10 years are prohibited from reuse unless the facility siting complies with Section (6)(A) of this Chapter.

**7. New Land Based Oil Terminal Facility Minimum Design Standards, Construction Standards and Related Measures.**

**A. Prior Approval.** Prior approval for construction of new facilities is required from the Department.

**B. Aboveground Oil Storage Tanks.**

(1) Design and Construction Standards. Aboveground oil storage tanks must be constructed of steel and meet or exceed one of the following design and manufacturing standards:

(a) UL-142, Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids;

(b) API650; or

(c) API-620, Design and Construction of Large, Welded, Low-Pressure Storage Tanks.

(2) Prohibited Tanks. Bolted or riveted construction is not acceptable for new or reconstructed tanks.

(3) Leak Detection. For tanks greater than 660 gallons, facilities must include a system of visual leak monitoring between the tank bottom and the impermeable containment as detailed in *API- 650.*

(4) Corrosion Protection. All tanks must have a cathodic protection system for any portion of the tank in contact with the soil or backfill, in accordance with *API Recommended Practice 651, Cathodic Protection of Aboveground Storage Tanks; API-650; and API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction; or NACE Standard SP0285, Corrosion Control of External Corrosion of Underground Storage Tank Systems by Cathodic Protection*  unless a cathodic protection assessment as described in Section (2) of this Chapter indicates that the corrosion rate will not reduce the floor thickness below the minimum allowed in *API 653* before the next required internal inspection date. An owner or operator may propose an alternate method of corrosion protection other than cathodic protection for review and approval of the Department, provided the method is based on good engineering principles and current industry practice.

(5) The use of galvanic corrosion protection systems on new facilities without the written permission of the Department is prohibited, except that galvanic protection systems may be applied to tank bottoms only where the metallic surface area exposed to the electrolyte is minimized through the application of a dielectric coating or the area is small due to the tank size or configuration.

(6) Painting. Tanks must be painted in accordance with nationally recognized industry standards, such as the Society for Protective Coatings publication *SSPC Painting Manual, Volume 1 Good Painting Practice*. Insulated tanks are exempt from this requirement.

(7) Tanks on Earthen Base Pads. Any tank on a prepared earthen pad must include the following:

(a) A base pad leak detection system constructed in accordance with the standards of *API-650*;

(b) A release prevention barrier;

(c) A support base constructed of compacted, clean, free-draining granular material such as sand, gravel, or crushed stone. The use of cinders and organic material is prohibited;

(d) Provisions to ensure positive drainage of water away from the support base;

(e) A support base elevation of at least 12 inches above the general grade (dike floor) after ultimate settlement; and

(f) Protection against erosion of the surface of the support base by use of good engineering practices.

(8) Tank Spacing. New, relocated, or reconstructed tanks must be separated in accordance with NFPA 30.

(9) Highway Locations. Tanks located near a highway must be protected from vehicular collisions.

**C. Piping, Valves and Pumps.**

(1) Fabrication Code. New and replacement piping must be designed, fabricated, tested, and maintained in accordance with codes of practice developed by nationally recognized associations such as API, ASME, ANSI, NFPA, PEI and STI. Installation of piping must meet or exceed current codes of practice and be in strict accordance with manufacturer specifications. Piping must be tested for tightness and all deficiencies remedied before the piping is placed in service. References to be followed include: ASME B31.1, Power Piping; ASME B31.3, Process Piping; ASME B31.4, Pipeline Transportation Systems for Liquids and Slurries; API RP1615, Installation of Underground Petroleum Storage Systems; NFPA 30; PEI RP 100.

(2) Identification. All aboveground piping and oil fill ports (for filling tanks and trucks) at multi product oil terminal facilities must be color coded as specified in *API 1637, Using the API Color-symbol System to Mark Equipment and Vehicles for Product-Identification at Gasoline Dispensing Facilities and Distribution Terminals.*

(3) Aboveground Piping. Aboveground piping must be adequately supported and must be protected from physical damage including but not limited to damage caused by freezing, frost heaving, flooding, and vehicular traffic. Aboveground piping must be painted or coated according to nationally recognized industry standards to prevent corrosion.

(4) Underground Piping. Installing underground piping must be avoided whenever possible. Piping installed after the effective date of this Chapter and in contact with the soil or in contact with an electrolyte must be adequately protected from corrosion in accordance with codes of practice developed by a nationally recognized association such as NACE or API. Underground lines must have secondary containment with interstitial space monitoring, except that runs in excess of 100 feet that are not able to be run aboveground for operational, safety and security reasons may be cathodically protected single walled pipe. References to be followed include: ASME B31.1; ASME B31.3; ASME B31.4; API 1615; NFPA 30; PEIRP 100; API 651; NACE SP-0169; NACE SP-0285; STI R892, Recommended Practice for Corrosion Protection of Underground Piping Networks Associated with Liquid Storage and Dispensing System.

(5) Tank Valves. Each connection to an aboveground oil storage tank through which liquid can normally flow must be provided with an NFPA 30 approved valve located as close as practical to the shell of the tank. The tank shell valve must be kept in the closed position when not in use, except at a staffed facility equipped with a functional continuous tank level monitoring system. At unstaffed facilities, a normally closed automatic valve must be installed immediately downstream of the shell valve on tanks serving a loading rack.

(6) Valve Access. Tank shut-off valves must be accessible and operable under all operating conditions including during a 24-hour storm, 100-year precipitation event.

(7) Pump Leaks. Pumps must be equipped with secondary containment such as drip pans or impermeable surfaces to catch leaks from bearings, packings and seals.

**D. Tank - Secondary Containment.**

(1) Capacity of Spill Containment Dikes. All oil terminal facilities shall have diked areas designed, constructed, and maintained to prevent oil from entering any waters of the State as described in Section (2) or adjacent property.

Aboveground tanks must be surrounded by a containment dike with a minimum height of 24 inches, and constructed as follows:

(a) Where a diked area contains one storage tank, the diked area must retain not less than 110% of the capacity of the tank;

(b) Where a diked area contains more than one storage tank, the diked area must retain not less than 110% of the capacity of the largest tank, deducting the volume of the other tanks in the diked area below the top surface of the dike; and

(c) Containment capacity for all facilities must be verified when modifications to the diked areas, or to the capacity of any storage tank within the diked area, are made. If no modifications are made, the containment capacity must be verified every 10 years and signed and sealed by a Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes. Dike walls that have eroded or degraded over time must be regraded or repaired. Documentation of verification, upgrade, and repair to containment areas must be maintained on site and made available for review by the Department.

(2) Dike Configuration. The NFPA 30 governs dike configuration for new facilities.

(3) Dike Impermeability. New facilities must have secondary containment with the base and walls designed for a permeability rate to water of 1 x 10-7 cm/sec, except where asphalt is the only oil stored in the diked area.

(4) Liner Design Specifications. The applicant shall submit to the Department for review and approval complete design plans and specifications for the liner and associated containment structures. The documents must be signed and sealed by a Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes. The plans and specifications must include, but are not limited to, the following:

(a) Liner subgrade and cover materials, placement and compaction;

(b) Liner materials, storage, handling, placement, anchoring, penetrations, attachment to structures, and seaming;

(c) The methods of field and laboratory destructive testing as required in paragraph (5) below;

(d) Methods of nondestructive testing of 100% of welded, extruded, or solvent seams; and

(e) A list and description of the manufacturer's oil compatibility certifications, installation certifications, and warranties.

(5) Liner Testing. Liner testing must meet the following requirements:

(a) Welded, extruded, or solvent seams for synthetic geomembranes. At a minimum, seam testing must be carried out twice daily at the beginning and end of days when seaming takes place, or whenever seaming personnel change, or when environmental conditions significantly change as determined by the liner specifications;

(b) Moisture content, hydraulic conductivity, and mass per unit area for every 50,000 square feet or per lot of geosynthetic clay liner delivered;

(c) Construction methods and moisture-density zone of acceptance for soil liners to be performed according to a statistically valid method approved by the Department and based on the size of the liner; and

(d) All welded, extruded and solvent seams must be tested by an approved non-destructive method.

Testing methods must conform to nationally recognized standards. If no standards exist, alternative methods must be approved by the Department.

Note: The American Society of Testing and Materials (ASTM), the Geosynthetic Institute (GSI), and the National Sanitation Foundation (NSF) are considered nationally recognized standards.

(6) Liner Quality Assurance (QA) Plan. The applicant shall submit to the Department for review and approval a liner QA plan which must include, but is not limited to, the following:

(a) A description of how the liner QA plan interfaces with the overall liner and containment structure design plans and specifications;

(b) Qualifications of the construction inspector. The inspector must be fully knowledgeable of the QA plan, independent of the liner manufacturer and fabricator, and empowered by contract to enforce all provisions in the liner QA plan and liner design plans and specifications;

(c) Qualifications of liner fabricator, lead seamer, quality control officer, and site supervisor personnel;

(d) Qualifications of the independent testing laboratory;

(e) The environmental conditions at which seaming or placement of the liner must be stopped or seaming techniques substantially modified;

(f) Seam inspection, rejection, or repair procedures for faulty seams or evidence of a faulty seam, or placement of liner determined through destructive testing, nondestructive testing, or inspection; and

(g) Record keeping and reporting requirements for QA activities.

(7) Compatibility of Geomembrane Liner. Geomembrane liners used for secondary containment must meet a short term compatibility testing (7-28 days) in accordance with ASTM D5747/D5747M before any new oil is put in the tank.

(8) Liner Installation Standards. All new geomembrane liners must be designed and installed in accordance with the manufacturers' recommendations. The design must include protection of the liner from equipment damage. A minimum of 6 inches of sand must be placed over the liner to protect the liner from damage.

(9) Detailed Design. The detailed design of new spill containment dikes must be signed and sealed by a Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes.

(10) Dike Stairways. Permanent fixed stairways must be provided for access to diked areas to prevent degradation of the dike walls.

**E. Facility Drainage Systems.**

1. Design. The water collection, drainage, discharge, and oil/water separator system must be designed and signed and sealed by a Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes. The design and operation collectively must provide for operational stresses likely to be encountered in Maine, such as frost action, a 24‑hour storm, 100-year precipitation event and other site specific factors. All buried or partially buried oil/water separators must be of a design and construction (approved by the Department) that will prevent releases due to corrosion or structural failure for the operating life of the system.

(a) The oil/water separator systems must be constructed or lined with material that is compatible with the expected contents of the system.

(b) Underground or inground oil/water separator system must be:

(i) Cathodically protected against corrosion;

(ii) Constructed of non-corrodible material;

(iii) Steel clad with non-corrodible material;

(iv) Designed in a manner to prevent the release or threatened release of any stored substance due to corrosion; or

(v) Installed at a site that is determined by a NACE certified corrosion expert to be unlikely to have a release due to corrosion during its operating life. Owners and operators shall maintain records that demonstrate compliance with the requirements of this provision for the remaining life of the tank.

(2) Oil/Water Separators. Oil/water separators must be designed, licensed, operated, and maintained according to *Pollution Control,* 38 M.R.S. §413 (Waste Discharge Licenses) if the effluent is discharged directly into the waters of the State. If the effluent will be discharged to a POTW, the oil/water separator must also be designed, licensed, operated, and maintained according to the requirements of the POTW (in order to meet their state and local license requirements). If the oil/water separator is required to be registered in accordance with *Rules for Underground Oil Storage Facilities,* 06-096 C.M.R. ch. 691, it must be installed by a Maine Certified Underground Oil Storage Tank Installer.

(3) Drain Valves. Drain valves must be easily accessible for closing in an emergency under all conditions of operations. Flapper valves are not acceptable.

(4) Dike Drainage.

(a) Control of drain water from inside a diked area must be by a valve outside the diked area, locked in the closed position except at times of drainage operations under supervision by personnel trained in the proper operation of drains and separators. Drainage control valves may be located inside the diked area at existing facilities where #6 oil or asphalt is the only oil being stored in the diked area, provided that these drainage valves are locked in the closed position except during drainage operations under supervision by trained personnel, and that the dike valves are exercised monthly.

(b) All drainage through the oil/water treatment system from a containment dike must be locked out from discharge except at times of supervised drainage. All drainage must flow through an oil/water separator

(5) Oil Storage and Handling Area. Facilities must be graded to collect surface run-off and discharge it through an oil/water separator to a location approved by the Department. Such separators must be designed, installed, operated, and maintained to collectively handle a 24-hour storm, 100-year precipitation event.

**F. Tank Truck and Tank Car Loading and Unloading.**

(1) Shut-Off Valves. NFPA 30 approved shut-off valves must be provided at the end of all loading and unloading points and must be maintained in a locked position except during properly supervised operations. Such valves must be accessible under all conditions of operations.

(2) Hose Spill Preventers. All vehicle loading points must be equipped with spill preventers designed to drain the transfer hose at the end of the transfer procedure.

(a) The spill preventer must be of sufficient size to contain the contents of the hose.

(b) A dry break system approved by the Department may be used in lieu of a spill preventer.

(3) Automated Equipment. The design of the piping, valves, pumps and hoses which convey oil from storage tanks to a tank truck or a tank car loading rack must be "fail-safe" engineered to prevent the spilling of oil.

(4) End Capping. Top loading arms at tank truck and tank car loading racks must be equipped with a containment device capable of preventing a discharge of oil when in standby service. Piping used for unloading tank cars or tank trucks must be securely capped or blank flanged and emptied of oil product when not in use. Out of service top loading racks at tank truck or tank car loading areas must be isolated or disconnected from the active portions of the facility.

(5) Spill Containment. Tank truck and tank car loading, and unloading areas, except for facilities handling only asphalt, must be provided with impervious secondary containment, that is designed, constructed, and maintained to contain spills in amounts up to the volume of largest compartment of any vehicle loaded or unloaded at the facility. The secondary containment systems in loading and unloading areas must be designed and constructed to prevent collection of stormwater runoff and must be connected to either a holding tank for removal and disposal or to an oil/water separator.

**G. Fire Prevention.** All facilities must be designed, built, operated, and maintained in accordance with the NFPA 30. A terminal facility unable to meet these requirements shall submit an alternate fire protection plan that has been approved by the State Fire Marshal’s Office and the local fire suppression agency.

**H. Physical Security.**

(1) Fencing. All facilities must be surrounded by a security fence. Fencing must be at least 6 feet high. Automatic entry gates operated by pass key and visual checks must be provided, and must remain locked except when the facility is in supervised operation or guarded. The Department may approve alternative security measures if it determines that the alternative measures meet the intent of this Chapter.

(2) Lighting. A minimum illumination standard of 50 lux is required for transfer areas including tank truck and tank car loading and unloading areas, pump areas, and entryways that would likely be the source of leaks either by accident or by acts of vandalism. Adequate lighting must be provided in accordance with the Illumination Engineering Society HB-10, Lighting Applications Standards.

(3) Facility Security Plan. Facilities must establish and implement a Facility Security Plan pursuant to 33 C.F.R. pt. 105 that is approved by the U.S. Coast Guard.

**I. Dock Facility.**

(1) Transfer Piping. The connection points of the oil transfer piping to the storage tanks, located on the dockside, must have NFPA 30 approved shut-off valves and check valves installed to prevent back-flow of oil should failure of dock hoses or other equipment occur.

(2) Spill Containment. All oil transfer points of connection must be provided with a spill containment system designed, constructed, and maintained so as to contain discharges that could result from a hose or connection point rupture.

The spill containment system must have a storage capacity of at least:

(a) Two barrels if it serves one or more hoses of 6-inch inside diameter or smaller, or one or more loading arms of 6-inch nominal pipe size diameter or smaller;

(b) Three barrels if it serves one or more hoses with an inside diameter of more than 6 inches, but less than 12 inches, or one or more loading arms with a nominal pipe size diameter of more than 6 inches, but less than 12 inches; and

(c) Four barrels if it serves one or more hoses of 12-inch inside diameter or larger, or one or more loading arms of 12-inch nominal pipe size diameter or larger.

(d) Spill containment must be properly positioned and adequately maintained, and an absorber must be available in case of overflows to minimize the loss of oil. The spill containment contents may not be allowed to spill into the water or onto the surrounding soil. Spilled oil, oil debris and contaminated soil must be disposed of in a manner acceptable to the Commissioner.

(3) Precipitation drainage locations (scuppers) in the dock containment area must be plugged prior to commencement of any oil transfers.

(4) Requirements for Protection Against Mechanical Damage. Concrete or other portions of the pier or wharf structures that are exposed to impact or abrasion by vessels or are subject to damage by floating ice or debris must be protected by an open fender system constructed of wood or other material. Provisions must be made to reduce the impact force exerted on the pier with such details of construction that reduces damage from ordinary operations to a reasonable minimum. The pier and wharf structures must be inspected for damage annually and repaired as necessary.

**J. Shop-Fabricated Aboveground Storage Tanks and Appurtenances.**

(1) Shop-Fabricated Aboveground Storage Tanks.

(a) Design and Construction Standards. Shop-fabricated aboveground storage tanks used to store flammable or combustible liquids must be constructed of steel and meet or exceed the design requirements of NFPA 30. Shop-fabricated aboveground storage tanks used to store non-flammable or non-combustible hazardous substances (as defined by *Uncontrolled Hazardous Substance Sites,* 38 M.R.S. §1362(1) must be constructed of materials compatible with the substance to be stored and designed in accordance with good engineering practices. All shop-fabricated aboveground storage tanks, including any integral secondary containment systems, must be installed according to the manufacturer's recommendations.

(b) Limited Use Tanks. Tanks constructed in accordance with UL 80, Standard for Steel Inside Tanks for Oil-Burner Fuels and Other Combustible Liquids, must only be used to supply fuel to oil-burning equipment.

(c) Secondary Containment. All shop-fabricated aboveground storage tanks must be located in diked areas meeting the requirements of Section (7)(D) of this Chapter, or designed with their own integral secondary containment system meeting the standards of one of the following: STI F911, Standard for Diked Aboveground Storage Tanks; STI F921, Standard for Aboveground Tanks with Integral Secondary Containment; or UL 2085, Standard for Protected Aboveground Tanks for Flammable and Combustible Liquids.

(d) Leak Detection. Shop-fabricated aboveground storage tanks must be designed so that the space between the bottom of the tank and the secondary containment can be either visually or electronically monitored.

(e) Corrosion Control. All shop-fabricated aboveground storage tanks must have a cathodic corrosion protection system for the portion of the tank in contact with the soils or backfill in accordance with API 651; PEI RP200, Recommended Practices for Installation of Aboveground Storage Systems for Motor Vehicle Fueling; STI R893, Recommended Practices for External Corrosion Protection of Shop Fabricated Aboveground Tank Floors; or NACE SP-0285. An owner or operator may propose an alternate method of corrosion protection other than cathodic protection for review and approval by the Department, provided the method is based on good engineering principles and current industry practice.

(f) Overfill Prevention.

(i) All shop-fabricated aboveground storage tanks with a capacity of over 20,000 gallons or with an integral secondary containment system that are used to store a flammable or combustible liquid must have:

a. A device which sounds an audible and visual alarm when the tank reaches 90% of capacity; and

b. During filling operations, a person from the terminal receiving the delivery shall monitor the transfer along with the truck driver.

(ii) All shop-fabricated aboveground storage tanks with a capacity of 20,000 gallons or less and that are used to store a flammable liquid must have one of the following:

a. A device which sounds an audible and visual alarm when the tank reaches 90% of capacity; or

b. A device which automatically stops the flow of the liquid into the tank when the liquid level of the tank reaches 95% of capacity.

During fill operations, a person from the terminal receiving the delivery shall monitor the transfer along with the truck driver.

(g) Painting. Tanks must be painted in accordance with the *SSPC publication Painting, Manual, Volume 1 Good Painting Practice*. Insulated tanks are exempt from this requirement.

(2) Piping, Valves and Pumps.

(a) Fabrication Code. All aboveground piping systems must be designed, constructed, installed and maintained in accordance with Section (7)(C)(1) of this Chapter.

(b) Pump and Valve Leaks. Pumps and valves must be equipped with secondary containment such as drip pans or impervious surfaces to catch leaks from bearings, packing and seals.

(c) Tank Valves. All shop-fabricated storage tanks connected to a loading rack must be equipped with a device such as a normally closed solenoid valve that prevents gravity flow from the tank in the event of a piping breach, unless tank inventory is reconciled daily. Valves on shop-fabricated storage tanks not connected to a loading rack and not in frequent use must be maintained in the closed position.

(d) Underground Piping. Underground piping must be avoided whenever possible. All underground piping must be designed, constructed, installed and maintained in accordance with 06-096 C.M.R. ch. 691 or *Rules for Underground Hazardous Substance Storage Facilities,* 06-096 C.M.R. ch. 695.

**K. Natural Hazard Risk Assessment.**

All facility infrastructure must be assessed for current flood risk and for future flood risk. Potential impacts on adjacent properties must be identified including the possibility for damage to existing infrastructure and movement of product or contamination to adjacent areas.

(1) The assessment must identify the infrastructure evaluated. Future flood risk evaluation must consider a timespan of 30 years from the date of the evaluation.

(2) The assessment must review previous flood information and any costs resulting from flood damage; evaluate current flood risks from a 100-year flood event; and evaluate future flood risks using storm surge and waves from a 100-year flood event added to both the projected intermediate and high sea level rise scenarios. The assessment must consider impacts including but not limited to erosion, collision, scouring, flooding, and flotation, including the buoyancy of any empty or partially empty tanks and pipelines.

(3) The assessment must consider how to meet the Facility Drainage System 24-hour, 100-year precipitation event requirements of Section (7)(E)(1) and (5) and the portion of Section (8)(K) that relates to these two Sections. The assessment must determine how stormwater management measures can accomplish this requirement and must include a timeframe for implementation of any measures needed to comply with these Sections. The implementation schedule must be completed within 5 years following the submittal of the Natural Hazard Risk Assessment report in Section (7)(K)(6).

(4) The worst case scenarios of hazards to vulnerable infrastructure must be considered in the assessment. Evaluation of potential impacts to critical infrastructure and operations including their consequences; identification of short- and long-term adaptation practices; prioritization of adaptive actions; costs of recommended adaptations; and presentation of recommendations that build resilience into the critical infrastructure must be included.

(5) An explanation of the data sources used in the assessment must be included in the final assessment document.

(6) A report detailing the results of the assessment must be included in the initial license application and any renewal applications. The report must clearly specify what adaptive measures, if any, are incorporated into the facility design based on the evaluation and must include an implementation schedule for these measures.

**8. Existing Land Based Oil Terminal Facility Minimum Design Standards, Construction Standards, and Related Measures.**

**A. Notification of Work.** The owner or operator shall notify the Department of substantial modifications, rehabilitation, and new construction including, but not limited to, the installation of new tanks and tank floors, tank repairs, the construction of new secondary containment, new dikes, and new dike floor liners prior to implementation, and excavations within 10 feet of underground piping. The designs must be signed and sealed by a State of Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes.

**B. Aboveground Oil Storage Tanks.**

(1) New Tanks. Any new aboveground oil storage tank added to an existing terminal must meet the rules and construction standards of Section (7)(B) of this Chapter. A new tank may vary from the spacing requirements if an alternate fire plan is approved by the State Fire Marshal’s Office and the local fire suppression agency.

(2) Reuse of Tanks. Existing aboveground oil storage tanks that have been closed may be reused only if the following conditions are met:

(a) The existing tank must have an ASME code stamp, API nameplate, or UL label; and

(b) Satisfactory documentation must be provided to the Department that the tank has been inspected by a qualified State of Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes and found to meet the specifications of API 650. The documentation must be signed and sealed by the professional engineer that conducted the inspection.

(3) Corrosion Protection. All existing aboveground oil storage tanks must have a cathodic protection system for any portion of the tank in contact with soil or backfill, in accordance with API RP 651, API 650, and API 653 or NACE SP0169, unless a cathodic protection assessment as described in Section (2) of this Chapter indicates that the corrosion rate will not reduce the floor thickness below the minimum allowed in API 653 before the next required internal inspection date. The cathodic protection system must be installed when a release prevention barrier is installed. The owner or operator may propose alternate corrosion protection measures addressed in API 651 other than cathodic protection for review and approval by the Department, provided the methods are based on good engineering principles and current industry practice.

Note: Impressed current cathodic protection systems are recommended for double bottom tanks.

(4) Painting. The exterior tank shell on existing aboveground oil storage tanks must be painted and maintained in good condition to prevent excessive rusting and or corrosion to the exterior of the tank. Tank painting must be in accordance with nationally recognized industry standards, such as the SSPC publication *Painting Manual, Volume 1, Good Painting Practice.* Insulated tanks are exempt from this requirement.

(5) Upgrade and Repair of Tanks. If an aboveground oil storage tank inspection reveals a discharge, excessive corrosion, excessive tank settlement, or any other deficiency which could result in a discharge, the tank must be repaired to standards equal to or better than the standards of original construction.

(a) Unacceptable levels of corrosion and tank settlement are as defined *in API RP 651, API 650,* and *API 653.*

(b) All riveted and bolted tanks must have all seams sealed, including rivets and bolts on the bottom and first course of shell plates. Heated oil tanks storing #6 oil or asphalt are exempt from this requirement.

(i) An oil terminal owner or operator shall notify the Department within 3 days of discovery of a weep. A weep is defined as a film or stain that travels down the tank one complete ring from the rivets, bolts, or seams of a riveted or bolted aboveground oil storage tank. The notification must identify the tank and the location of the weep as it appears on the tank. Within 14 days of discovery of the weep, the oil terminal facility owner or operator shall either drain the tank below the level of the weep or propose an alternate method for controlling the weep acceptable to the Department prior to the weep being properly repaired.

(ii) A weep which comes in contact with the ground surface must be reported to the Department within two hours of its discovery. The oil terminal owner or operator shall drain the tank below the level of the weep within 14 days of discovery. The tank may not be filled above the level of the weep until the Department has received a report from the terminal owner or operator demonstrating that the weep has been properly repaired.

(c) Tank liners are not an acceptable form of tank bottom repair unless provisions are made for leak detection between the liner and the repaired steel bottom.

(6) Release Prevention for Tank Bottoms. Release Prevention Barriers (RPB) with leak detection must be provided for all active field constructed tank bottoms. Tanks used for asphalt and #6 fuel oil are exempt from the requirement for an RPB.

(a) An RPB may include a steel double bottom, a synthetic liner, a geosynthetic clay liner, a clay liner or existing soils under the tank provided they meet the standard in Section (8)(B)(6)(b) below, or such system as the Commissioner may determine provides the same protection from oil migration due to leakage and equivalent leak detection.

(b) Engineered clay or an existing soil liner under a tank may serve as an RPB if the engineered clay is at least 12 inches thick or the existing soil layer is at least 24 inches thick and meets the following water permeability standards:

Gasoline, ethanol 1 x 10-6 cm/sec

Mid Distillates 1 x 10-5 cm/sec

Crude Oil 1 x 10-5 cm/sec

#4, #5 Fuel Oils 1 x 10-4 cm/sec

Permeability of clay or existing soil RPB's must be determined by a Maine licensed professional engineer or licensed geologist using a method capable of testing both horizontal and vertical permeabilities. A soil survey plan, test method, testing location and test protocol must be submitted to the Department for approval.

(c) All tanks except those storing asphalt and #6 fuel oil must be fitted with leak detection upon installation of an RPB. Acceptable methods of leak detection are shown in *API 650*. Tanks using existing soil liners must have leak detection comprised of permeable sand or gravel of adequate thickness with collection pipes so that a leak can be detected before passing through the existing soil liner, or such other system as the Department may find acceptable. The Department considers criteria such as speed of detection and reliability for both the system and the leak detection method, as well as service life in evaluating and approving an alternate method.

**C. Piping, Valves and Pumps.**

(1) All new piping runs added to, or replacing, existing runs at an existing facility must be constructed in accordance with the requirements of Sections (7)(C)(1) and (7)(C)(4) of this Chapter. For purposes of this Section, "replacing" means removal and installation of 25 or more feet of the new piping run.

(2) Underground Piping. All existing underground piping must be surveyed and shown on a site plan. The plan must clearly show the location, material, size and estimated burial depth of all underground piping.

(3) Identification. All aboveground piping at facilities that handle multiple types of products must be marked or labeled to clearly identify the oil product contained in the piping. All fill ports (into tanks or trucks) must be color coded or labeled as specified in API 1637.

(4) Pipe Supports. Aboveground piping must be adequately supported and protected from physical damage caused by freezing, frost heaving, vehicular traffic, and any other reasonably foreseeable potential cause of damage.

(5) Pressure Relief. Pressure relief valves or an alternate pressure venting procedure must be provided on piping that could be blocked in and filled with oil.

(6) Corrosion Protection. Aboveground piping must be painted or coated to prevent corrosion. Underground piping must be cathodically protected in accordance with *NACE SP0285.*

(7) Tank Valves. Each connection to an aboveground oil storage tank through which liquid can normally flow must be provided with an NFPA 30 approved valve located as close as practical to the shell of the tank. The tank shell valve must be kept in the closed position when not in use, except at a staffed facility equipped with a functional continuous tank level monitoring system. In addition, a normally closed automatic valve must be installed immediately downstream of the shell valve on tanks serving a loading rack at unstaffed facilities. Tanks used exclusively for storing asphalt are exempt from this requirement.

(8) Impact Protection. Piping must have adequate protective guards where vehicular impact or other physical impact is possible.

(9) Pump Leaks. Pumps must be equipped with secondary containment to catch leaks from bearings, packings and seals.

**D. Tank Secondary Containment.**

(1) All new, reconstructed, or relocated tanks installed in a new diked area at an existing facility must meet the requirements of Section (7)(D) of this Chapter.

(2) A new tank in an existing diked area must have secondary containment with leak detection for the tank bottom. This may be accomplished through use of a double bottom tank or by providing a new tank base pad that meets the permeability standards of Section (7)(D)(3) of this Chapter. The remainder of the diked area must meet the requirements of Section (8)(D)(5) below.

(3) Capacity of Spill Containment Dikes. All existing oil terminal facilities must meet the requirements of Section (7)(D)(1) of this Chapter.

(4) Dike Configuration. The standards of the *NFPA 30* govern dike configuration for existing facilities as far as practical.

(5) Dike Impermeability. The base and walls of a diked area surrounding an aboveground storage tank must be designed, constructed, and maintained in a condition that prevents any release of oil within the diked area from reaching a surface water body within 72 hours, or ground water within 72 hours as specified below in (a)(iii).

(a) A site assessment is required under the following conditions:

(i) When any previous release within a diked area has reached surface water within 72 hours of the release; or

(ii) When the documented dike base and walls soil type, permeability, and the distance from the diked area to the nearest downgradient surface water body is less than indicated in the table below:

**Soil Type Permeability in centimeters per second Distance (feet)**

Clay, silt, silt and clay <5 x 10-4 N/A

Silty sand <4 x 10-3 13

Clean find sand <1 x 10-2 28

Clean medium sand <5 x 10-2 45

Clean coarse sand <2 x 10-1 72

Sand and gravel <3 x 10-1 101

Clean medium gravel <1.4 246

Shale <5 x 10-6 6

Sandstone <2 x 10-3 11

Fractured rock sites require a site assessment; and

(iii) When any release within a diked area has reached ground water more than 30 feet horizontally outside of the diked area within 72 hours.

(b) If the site assessment indicates that a release of the specific oil within the diked area will not be prevented from reaching surface water, or ground water as specified in Section (8)(D)(5)(a)(iii), within 72 hours, the diked area must be improved to meet this requirement within one year of the site assessment.

(c) The detailed design of new or modified secondary containment dikes must be signed and sealed by a State of Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes.

(6) Valve Access. Tank shut-off valves must be accessible and operable during a 24-hour storm, 100-year precipitation event and all operating conditions.

(7) Dike Stairways. Permanent fixed stairways must be provided for access to diked areas to prevent degradation of dike walls.

**E. Leak Monitoring and Detection.**

(1) The Department may require monitoring wells and leak detection devices at existing facilities known or reasonably suspected to be a source of contamination.

(2) Existing monitoring wells must be checked for free phase product and depth to ground water annually or as directed by the Department as a licensing requirement of oil terminal facilities.

(3) Monitoring wells must be designed and constructed as described in Appendix A. New monitoring wells must be located to avoid penetrations in any diked area liner. Any ground water monitoring well in the floor of a diked area containing active tanks and piping must be designed and constructed in such a way that the well does not become a conduit for contaminants to move to ground water or surface water in the event of a discharge.

**F. Existing Tank Truck and Tank Car Loading and Unloading Spill Containment.**

(1) Except for facilities handling only asphalt, tank truck loading and unloading areas must be provided with impervious secondary containment that is designed, constructed, and maintained to contain

spills in amounts up to the volume of the largest compartment of any tank truck loaded or unloaded at the facility. These secondary containment systems must be designed and constructed to prevent the collection of storm water runoff and must be connected to either a slop tank for removal and disposal or to an oil water separator.

(2) Except for facilities handling only asphalt and #6 oil, tank car loading and unloading areas must be equipped with a device that automatically stops the flow of the liquid into the tank car when the liquid level in the tank car reaches 95% of capacity. The loading and unloading areas must also be provided with impervious secondary containment designed, constructed and maintained to prevent a discharge from coming in contact with soils and ballast associated with the rail line. The secondary containment must be designed to prevent the collection of storm water runoff and must be connected to either a slop tank for removal and disposal or to an oil water separator. Storm water drainage from facilities handling only #6 oil and asphalt must be connected to a slop tank for removal and disposal or an oil water separator.

**G. Reopening a Closed Facility.** An oil terminal facility that closed or underwent facility closure must meet the standards for existing facilities if reopening within 10 years of the closure date. Closure date is the date when the facility last operated as a licensed oil terminal facility. Any facility reopening after a closure of more than 10 years must meet the standards for a new facility, including the siting standards in Section (6) of this Chapter.

**H. Other Requirements.** All existing oil terminal facilities must meet the requirements of Sections (7)(E), (7)(F) (1)-(4), (7)(G), (7)(H), (7)(I) and (7)(K) of this Chapter.

**I. Shop-Fabricated Tanks.**

(1) New shop-fabricated tanks must meet the requirements of Section (7)(J) below. New tanks may vary from the spacing requirements if an alternate fire plan is approved by the State Fire Marshal’s Office and local fire suppression agency.

**9. Standard Operating Procedures.**

**A. Transfers Between Land Based Oil Terminal Facilities and Vessels.**

(1) Personnel. For transfers at an oil terminal facility, the facility must provide the transporter with a written transfer procedure. This procedure must be acknowledged in writing by the transporter. A transfer is considered to begin when the person in charge on the transferring vessel or facility and the person in charge on the receiving facility or vessel first meet to begin completing the declaration of inspection.

(2) Inspections. Inspections are required at the beginning of each transfer and as needed to verify the tightness of the loading and offloading lines, valves, and other attached apparatuses. Inspection logs must be retained at the facility for at least 3 years.

(3) Tank Capacity. Persons transferring oil shall assure that the high level alarms on the receiving tank are set at such a level that if an alarm should occur during the oil transfer there would be sufficient time to shutdown the oil transfer operation prior to overfilling the tank. This alarm level must be verified to the Department's satisfaction by a signed agreement with the local fire suppression agency or by demonstrating that there is sufficient shutdown time to the Department.

(4) Bonding Cable. Pipelines on wharves must be adequately bonded and grounded if Class I or Class II liquids are handled. If excessive stray electrical currents are encountered, insulating joints must be installed. Bonding and grounding connections on all piping must be located on the wharf side of the hose riser insulating flanges. The bonding cable must incorporate a meter or other suitable positive means of determining a ground. Typical methods for protection against stray current hazards at wharves are illustrated in *API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*. Any bonding cable employed between the wharf piping and the vessel must employ an explosion-proof switch as a method of completing the connection. Insulating flanges properly installed in accordance with API 2003 can be used instead of a bonding cable to isolate the vessel from the terminal piping during product transfers across the pier.

(5) Safe Transfer Operations. Oil transfer operations are not permitted when any of the following conditions arise:

(a) If any weather-related condition develops that, in the opinion of the dock watchman, terminal supervisor or watch officer, is too severe for operations to be safely continued;

(b) If a fire occurs on the dock, tank vessel, adjacent tank vessel, or in the nearby vicinity;

(c) If a tank vessel breaks loose or if another vessel comes alongside which is not under control or is emitting sparks from its stack or is apt to collide or to otherwise present a hazard to the tank vessel in berth at the terminal;

(d) If an oil spill occurs aboard the tank vessel, an adjacent vessel, or on the dock, or if a leak develops in a joint of hoses or piping which is not able to be stopped by tightening;

(e) If in the opinion of the dock watchman, terminal supervisor, or watch officer a vapor condition develops aboard or around the tank vessel or dock which would be too serious to safely continue operations;

(f) If any other emergency occurs which, in the opinion of the dock watchman, terminal supervisor, or watch officer constitutes a potential hazard to the tank vessel or facilities; or

(g) If at any time the high level alarm system within the terminal activates to warn of a possible or pending overflow.

(6) Illumination. A person may not transfer or cause to be transferred or consent to the transfer of any bulk oil after dark unless the point of transfer is illuminated to a minimum standard of 50 lux.

(7) Open Hatch Transfer. Transfer of oil by means of a hose through an open hatch is prohibited. An exception may be made only when an emergency arises and this is the only means available to move oil from one vessel compartment to another or to unload oil from a vessel for purposes of reducing or preventing pollution, or for preventing foundering. Such emergency exceptions are allowed only when all possible precautions to prevent discharge to the waters of the State have been taken. The owner or operator shall notify the Commissioner or the Commissioner's designee and the local fire suppression agency prior to commencing such emergency transfer operations.

(8) Sample Collection. A terminal operator may not transfer or cause to be transferred or consent to the transfer of any bulk oil until a sample of the oil to be transferred has been collected, identified by proper labeling, and stored in a place acceptable to the Department. Oil terminal facilities with automatic sampling capabilities are not required to presample. The sample must be stored for a minimum of fifteen days. The Department shall determine the information to be provided with each sample and may require chemical analysis of the sample. Sampling must be done in accordance with Appendix B. Samples must be stored at the facility or at the lab where the samples are analyzed in accordance with chain-of-custody protocols.

(9) Anticipated Transfer. The terminal owner or operator shall notify the Supervisor of the appropriate Department Regional Office of the Division of Response Services, at least 12 hours in advance of any transfer of bulk oil. The notification must include the following information:

(a) Terminal name and location, or anchorage if the transfer will be offshore;

(b) Approximate amount of oil to be transferred;

(c) Oil type;

(d) Vessel name(s); and

(e) Expected time and date of vessel arrival(s).

Should unusual circumstances make it impossible to provide 12-hour notice, the terminal operator shall notify the Commissioner as soon as possible. Notification is not required for bunkering.

(10)Declaration of Inspection. A copy of any "Declaration of Inspection" required by the United States Coast Guard for a tank vessel transferring oil at an oil terminal facility must be in the possession of the terminal operator or the operator's representative and must be available to the representative of the Commissioner who shall, on demand, be given the opportunity to verify that the condition of the vessel is as stated in the "Declaration of Inspection."

(11)Other Reports and Forms. The oil terminal facility operator shall also complete and submit such other forms, checklists, and reports as the Commissioner may require.

(12) General Safety Provisions.

(a) Signs. During the time a tank vessel is in berth, a warning sign carrying letters not less than 2 inches high on a contrasting background must be displayed on the dock and near the gangplank. This sign must read substantially as follows: WARNING-NO OPEN LIGHTS, NO SMOKING, NO UNAUTHORIZED VISITORS.

(b) Hazardous Vapor. When in the opinion of the terminal operator or the Commissioner's representative a hazardous vapor condition develops on a dock or on any vessel, all transfer operations involving such vessels must be stopped and all sources of ignition such as smoking, use of matches, lighters and open flame except boiler fires must be eliminated and prohibited.

(c) Transfer of Sour Crude. An oil terminal facility must take special precautions for the transfer of sour crude oil to minimize the release of vapors during the transfer period.

(d) Multiple Vessel Mooring. A tank vessel may not be secured alongside another tank vessel at a pier except while taking bunker fuel aboard. A tow boat must stand by alongside or in the notch during the transfer of bunker fuel from a bunker vessel to a tank vessel. The bunkering vessel must be moved away from the tank vessel immediately after completion of the loading process.

(13)Vessel Pre-Transfer Conference. A person may not commence or consent to the commencement of bulk oil transfer operations at an oil terminal facility unless the following items have been reviewed, agreed upon and complied with by both vessel and facility personnel:

(a) A sufficient number of adequately trained oil terminal facility personnel are assigned to be constantly on duty during cargo transfer operations to keep the transfer operation under constant observation and to ensure immediate action in case of a malfunction;

(b) Cargo sequence for loading or discharging products and the proper pipe for each product must be established;

(c) The handling rate at which oil will be transferred must be established. Reduced rates are required when commencing transfer, changing the lineup, topping off tanks or nearing completion of transfer. The amount of time to be given when the vessel or terminal desires to start, or stop, or change the rate of flow must be determined;

(d) A positive communication and signal system must be operable during transfer operations;

(e) The emergency procedures to be followed in order to stop and contain any discharge must be established;

(f) Vessel and facility personnel responsible for transfer shall always be clearly identifiable. Prior to transfer operations, terminal and vessel personnel responsible for transfer shall be made known to each other; and

(g) The oil terminal facility must have written operation guidelines pertaining to dock operations for vessels coming to or alongside its dock during abnormal weather conditions.

(14)Transfer Hoses. A person may not transfer or cause to be transferred or consent to the transfer of any oil between an oil carrying vessel and an oil terminal facility unless the following conditions are met:

(a) All oil terminal facility transfer hoses must be of a type designed specifically for the oil transferred. Transfer hoses must be tested annually to 1.5 times the maximum working pressure

(i) For pipe that can be visually examined, the test pressure must be maintained for a minimum of 10 minutes and held for such additional time as may be necessary to conduct the examination for leakage, or

(ii) For pipe that is buried or insulated and cannot be visually inspected, the pressure must be maintained for one hour.

(b) As provided for below, each oil terminal facility hose must be marked with:

(i) The products for which the hose is to be used for or the words "oil service";

(ii) Maximum allowable working pressure;

(iii) Date of manufacture; and

(iv) Date of the most recent test performed.

The information described in subparagraphs (i-iv) above need not be marked on the hose if it is recorded elsewhere in the hose records at the facility and the hose is marked to identify it with the location of that information. The logbook or records must be available for inspection on demand by a representative of the Commissioner.

(c) Hoses must be supported to avoid crushing or excessive strain. Flanges, joints, and hoses must be checked visually for cracks and wet spots before each use.

(d) Oil terminal facility hose handling rigs must allow adjustment for vessel movement and hoses must be long enough so that they are not strained by any movement of the vessel.

(e) Hose ends must be blanked tightly when hoses are moved into position to be connected and immediately after they are disconnected, and must be drained either into the vessel tanks or into suitable shore receptacles before they are moved away from their connections.

(f) Hoses may not be permitted to chafe on the dock or vessel or be in contact with hot surfaces such as steam pipes. Hoses may not be exposed to any sources of corrosion.

(g) Hoses no longer in service must be removed from the transfer area.

(15)Mooring Lines. Mooring lines must be tended during transfer operations to prevent excessive movement of the vessel.

(16)Fire Main Connections. Serviceable fire hose sufficient to reach all parts of the vessel and dock with approved combination nozzles attached must be connected to the fire main on the vessel and/or on the dock and be ready for instant use during the time a vessel is in berth. The fire main must have a master valve at the head of the dock so the fire main can be kept dry in cold weather and wet in warm weather. The fire main on the dock must be at least 6 inches in diameter. The fire main must always be charged to the master valve. The owner or operator of an oil terminal facility not meeting these requirements shall file an alternate fire protection plan with the Department. The alternate plan must be approved by the State Fire Marshal’s Office or local fire suppression agency.

(17)Fire Wires. During transfer operations, fore and aft fire wires must be rigged on the offshore side of the vessel for use by tugs in removing the vessels from the pier in event of fire.

(18)Vessel to Shore Transfer. A person may not transfer or cause to be transferred or consent to the transfer of any bulk oil from any tank vessel to a land based oil terminal facility unless:

(a) All cargo risers not intended for use in the transfer are blanked;

(b) Sea valves connected to the cargo piping and stern loading connections are tightly closed and sealed with a numbered seal which is logged in the logbook of the vessel;

(c) Piping and valves in the pump rooms and on deck are checked by the master of the vessel, senior deck officer or deck officer on duty, or licensed tanker man to see that they are properly set for discharging cargo. An additional check must be made for the same purposes each time the setting is changed;

(d) Full rate of transfer is not attained until shore lines are proven clear; and

(e) On completion of transfer operations, hoses or other connecting devices are drained of the remaining oil. A drip pan must be in place when breaking a connection and the end of the hose or other connecting devices must be blanked off before being moved.

(19)Shore to Vessel Transfer. A person may not transfer or cause to be transferred or consent to the transfer of any bulk oil from a land based oil terminal facility to any tank vessel unless:

(a) All sea valves connected to the cargo piping, stern discharge and ballast discharge valves are closed and sealed with a numbered seal which is logged in the logbook of the vessel and with the responsible vessel officer of the vessel;

(b) All hose riser valves not to be used in the transfer are closed and blank flanged, and all air valves on headers are closed;

(c) During the topping off process, special attention is paid to the loading rate, the number of tanks open, the danger of air pockets and the inspection of tanks already loading. Shore personnel must be given notice of the slowdown for topping off; and

(d) Upon completion of loading, all tank valves and loading valves are closed. After draining, hoses must be disconnected and hose risers blanked.

(20)Scuppers. A person may not transfer or cause to be transferred or consent to the transfer of any bulk oil between a tank vessel and a land based oil terminal facility unless the scuppers of the vessel are plugged watertight during the oil transfer operation, except on tank vessels using water for deck cooling. However, it is permissible to remove scupper plugs as necessary to allow run-off of water provided a vessel crew member stands watch to re-close the scuppers in case of an oil discharge.

(21)Tank Tops and Hatch Covers. When transferring oil, tank tops and hatch covers must be closed. Ullage caps or plugs may only be opened on tanks that are to be loaded or unloaded and all open ullage holes must be covered with flame screens which must be kept in place during the transfer except for the minimum time necessary to observe transfer progress, take samples or take ullage readings. If a tow boat or other vessel such as a bunker barge or lighter is moved alongside for the purpose of serving the vessel, and if that tow boat or other vessel is steam propelled or propelled by an internal combustion engine, tank tops, tank hatches and ullage plugs or caps must be kept open only on those tanks from which oil is being withdrawn. Any such open ullage plugs or caps must have flame screens in place. When there is no longer any possibility of sparks or other source of ignition, normal procedure may be resumed.

(22)Ports and Doors to Crew Quarters. When loading and unloading oil, all ports and doors facing the cargo decks or facing a breeze bringing vapors from another vessel must be closed except to allow for passage of personnel.

(23)Blowing of Boiler Tubes. During transfer operations, blowing of boiler tubes or other work on the boilers which could cause the emissions of sparks or soot from the stacks is prohibited.

(24)Spillage During Transfer. Transfer operations must cease if a discharge of oil to the waters of the State occurs during such transfer. Operations may resume when, in the judgment of the Commissioner's representative adequate steps have been taken to control the discharge and to prevent further discharge. In making this judgement, the Commissioner’s representative may consult with the United States Coast Guard or Local Fire Chief, if necessary.

(25)Contingency Plan. Each owner or operator of an oil terminal facility shall have available for inspection by the Commissioner or a representative of the Commissioner, a copy of any oil discharge response plan required to be submitted to the President of the United States under the federal OPA 90.

(26)Operations Plans. The owner or operator of each oil terminal facility shall have an operations plan available for inspection upon request of the Commissioner or representative of the Commissioner. The operations plan must describe in detail the equipment and procedures used at that terminal for the prevention of oil spills and the protection of the public health, safety, welfare, and environment.

(27)Spill Prevention Control and Countermeasure (SPCC) Plan. The owner or operator of an oil terminal facility shall comply with all the requirements of the Spill Prevention Control and Countermeasures Plan in *Oil Pollution Prevention,* 40 C.F.R. pt. 112, incorporated by reference herein.

(28)Inventory Records and Fees. Records of all monthly fees paid to the Maine Ground and Surface Waters Clean-up and Response Fund for all applicable product transfers, annual reports on transfers, and third party observer records must be available for inspection upon the request of the Commissioner or a representative of the Commissioner. All inventory records must be retained for a minimum of 10 years. Fees on transfers must be paid monthly and accompanied by the applicable Department form. If no transfers are received during a month, the form must be filed with the Department stating that no transfers occurred. In the case of an enforcement action, the record retention timeframe is automatically extended until the action is resolved.

**B. Booming of Vessels**

(1) All tank vessels and tank barges, engaged in transfer operations, must be protected by an oil boom device to catch and contain oil discharges. The boom must completely surround the vessel at a minimum distance of 50 feet from the vessel and be secured in place by sufficient anchors, except:

(a) When engaged in the actual vessel to vessel bunkering operations while at anchorage;

(b) When personnel safety conditions, weather, wind, sea, or ice conditions are such that a boom is not able to be wholly or partially deployed, and the terminal operator reports this fact to the Commissioner. Reporting must be prior to transfer, whenever conditions develop which require removal of the boom, or when conditions are such that only a partial boom is appropriate to deploy. If the Commissioner's offices are closed, reporting must be on the next working day following the transfer; or

(c) When a portion of the oil has a flash point of -45 F or less, and an ignition temperature of 536 For more, such as gasoline.

(2) The boom used to enclose the tank vessel must be of a type suited to the conditions of wind, currents, and waves found at the transfer site at the time the transfer takes place, and must be capable of retaining the maximum most probable discharge from the tank vessel under the conditions normally found at the transfer site at the time the transfer takes place unless subparagraph (1)(b) applies. Maximum most probable discharge means a discharge of: (1) 2,500 barrels of oil for a vessel with an oil cargo capacity equal to or greater than 25,000 barrels; or (2) 10% of the vessel's oil cargo capacity for vessel with a capacity of less than 25,000 barrels.

(3) If a terminal operator believes it is impossible or wholly impracticable to implement the booming requirement in whole or in part on a regular basis, the operator may apply to the Department for complete or partial exemption from this requirement. The marine oil terminal application must set forth in detail the reasons why such complete or partial exemption should be granted. The Department may set any reasonable conditions in granting any such exemption.

**C. Land Based Oil Terminal Facilities.**

(1) Inventory Control/Overfill Protection.

(a) Inventory Reconciliation. The liquid level in a tank must be gauged at least once every 7 days and the measurements compared to previous readings. A record of the measurements must be maintained for inspection by the Commissioner or representative of the Commissioner. Tank gauging also is required prior to any delivery of oil into a storage tank at a facility.

(b) Mandatory Loss Reporting. Any liquid level measurements that, after reconciliation of inventory, indicate a loss of liquid of at least 0.5% of throughput on a monthly basis, must be immediately investigated. This investigation must include determining if a loss of material has occurred, the estimate of how much material is unaccounted for, the reason for the loss, and what happened to the material. The potential loss of material in excess of 0.5% must be reported to the Commissioner:

(i) Within 24 hours of discovery of the potential loss, if the investigation is not concluded, or

(ii) Within 2 hours of discovering that the loss was a result of a spill or leak.

All investigations for potential loss of material in excess of 0.5% must be kept on file for review by the Department.

(c) Overfill Prevention. Tank overfilling must be prevented by the following measures:

(i) High liquid level alarm with audible and visual signals; and

(ii) High-high liquid level alarm with audible and visual signals.

(d) Overfill protection systems must be tested before each transfer or monthly, whichever is the least frequent.

(2) Maintenance and Inspection. Prior to operation and as a condition of continued operation of an oil terminal facility, a maintenance and inspection program must be implemented by the facility operator as follows:

(a) Daily visual inspection of aboveground tanks, piping, equipment and discharge control devices and surrounding areas to detect possible oil discharges and to determine and carry out any maintenance necessary to prevent discharges from occurring. The operator shall make a list of daily inspection procedures and inspection logs available upon request of the Commissioner or representative of the Commissioner.

(b) A documented monthly visual inspection of the facility, including but not limited to, tanks and all ancillary devices (vents, water drawoff, etc.), valves, piping, spill containment dikes and other spill holding areas, oil/water separators and equipment.

(c) Monthly visual tank inspection, including, but not limited to the following:

(i) Inspection of exterior surfaces of tanks for discharges and maintenance deficiencies;

(ii) Identification of cracks, wear, corrosion, thinning, poor maintenance and operating practices, settlement, swelling of tank insulation, malfunctioning equipment, structural or foundation weaknesses; and

(iii) Inspection and monitoring of discharge detection systems, or warning systems.

(d) Tank De-watering. An appropriate schedule for removal of water from tanks must be included in the maintenance and inspection program. Maintenance to remove water from tanks must be appropriately handled. Discharge of water from tank bottoms must be to an appropriate treatment facility. Oil removed from the tank as part of the water bottom drawoff maybe returned to the tank.

(e) Cathodic Protection System. A monthly inspection must be performed on any impressed current cathodic protection system. Monthly voltage and current readings must be in the range to provide adequate cathodic protection levels per NACE SP0169 for underground piping or NACE SP0193 for above ground storage tanks. An annual structure to soil and structure to structure potential test must be performed by a cathodic protection tester for impressed current systems as well as annual structure to soil potentials for galvanic systems. All readings and repairs must be documented and made available at the time of the inspection and submitted to the Department at the request of the Commissioner or the Commissioner’s representative.

(f) Underground Piping. All underground oil piping must be inspected or tested to verify the integrity of the piping in accordance with *API Standard 570, Piping Inspection Code: In-Service Inspection, Rating, Repairs and Alternation of Piping Systems.* Verification by pressure testing must consist of holding pressure at 1.5 times the maximum operating pressure for a period of one hour on an annual basis. Verification by use of internal inspection devices designed to verify the structural integrity of the pipe by measuring pipe wall thickness and indicating geometric irregularities of the piping is an acceptable alternative. Verification by the use of internal inspection devices must be performed no more than 5 years from the most recent internal inspection and every 5 years thereafter. Pressure testing or internal inspection is not required on underground piping equipped with secondary containment or a leak detection system. The Commissioner may also require testing if there is reason to suspect a discharge.

(g) Aboveground Piping Tightness Testing. Tightness testing is required for aboveground piping no more than 10 years after installation and every 5 years thereafter in accordance with *API 570.* Aboveground piping must be hydrostatically pressure tested to 1.5 times the maximum operating pressure for a period of one hour. For the purpose of this paragraph a hydrostatic pressure test may be performed using hydrocarbon product or water. Verification by use of internal inspection devices, designed to verify the structural integrity of the pipe by measuring pipe wall thickness and indicating geometric irregularities of the piping, is an acceptable alternative. Verification by internal inspection devices must be performed no more than 5 years after the most recent internal test and every 5 years thereafter. If the piping, including insulated piping, can be visually inspected 360 degrees around over its entire length, then tightness testing is not required.

(h) Internal Tank Inspection. All field constructed tanks must be internally inspected as follows:

(i) Tanks with an RPB that have no internal tank bottom liner, no cathodically protected bottom, and that do not contain # 6 fuel oil or asphalt must be internally inspected no more than 10 years after a prior internal inspection, and every 10 years thereafter;

(ii) Tanks with an RPB, an internal tank bottom liner, a cathodically protected bottom, and that do not contain # 6 fuel oil or asphalt must be internally inspected no more than 20 years after a prior internal inspection, and every 20 years thereafter;

(iii) Tanks containing #6 fuel with or without a cathodically protected bottom must be internally inspected no more than 20 years after a prior internal inspection, and every 20 years thereafter;

(iv)Tanks containing asphalt with or without a cathodically protected bottom must be externally and internally inspected no more than 20 years after a prior external/internal inspection, and every 20 years thereafter.

(i) Internal inspections must be in accordance with *API 653.* If, during an inspection, evidence is found of a change from the original physical condition of the tank, then the suitability of the tank for continued service must be evaluated in accordance with *API 653*. Internal inspections and suitability for service evaluations must be conducted by an *API 653* certified inspector. Inspection records must be retained for review by the Commissioner or representative of the Commissioner. Any hole or failure of a tank or piping must be reported to the Department.

(j) For the purpose of this Chapter, the following inspection requirements must meet the intent of API 653, Section 6.5, *Alternative to Internal Inspection to Determine Bottom Thickness for Asphalt Tanks*.

(i) Inspections for indications of asphalt seepage and foundation stability, such as erosion or fill migration or settlement, must be performed around the exterior perimeter of the tank where the tank floor is flush with the ring wall foundation or pad foundation. For the purposes of this Section, the pad foundation refers to earth or concrete.

(ii) The area around the external shell to floor joint must be inspected for indications of seepage or cracked weld seams.

(iii) If the tank wall or floor is of riveted construction, rivets must be inspected for indications of seepage or corrosion which could indicate a rivet losing strength. Insulation must be temporarily removed to allow inspection of rivets at 10 to 16 locations. If the inspection reveals a significant number of leaking rivets, a weep for walls and 25% of the 10 to 16 locations for a floor, then an expanded detailed inspection plan must be prepared and submitted to the Department for approval. Subsequent inspections must consist of inspection locations in areas not previously inspected.

Repair of leaking rivets may be made using the best acceptable industry practices in use at that time. Thermal expansion and contraction of the shell, rivet and hole must be accounted for in determining the proper repair procedure.

(iv) The tank perimeter must be inspected for indications of tank settling such as floor or shell deformations. If the exterior of the tank is insulated, inspections for shell deformation must be conducted from the interior of the tank. The exterior floor elevations must be checked at 8 evenly spaced locations around the perimeter of the tank using a level. Records of the elevations must be maintained for comparison with measurements taken during subsequent inspections to detect any long-term settling.

(v) Floor thickness must be measured at 6 to 8 locations distributed throughout the interior bottom. At least one of these points must be within 6 inches of the shell. Asphalt at these points must be removed to expose bare metal. If there is any evidence of external or internal corrosion of the tank shell or floor, the floor thickness must be measured at the suspected point of minimal floor thickness. The minimum floor thickness observed must be used to compare with acceptable minimum thicknesses. If corrosion is present, allowances must be made for future metal loss in determining whether to replace the tank bottom or schedule for the next inspection.

(vi) In the event that inspection of the tank reveals weld cracks, leaking rivets or other indications of joint failure, the entire floor must be cleaned and inspected, or replaced with a new floor in accordance with API 653.

(vii)The inspection of the balance of the tank and any repairs or modifications must be in accordance with API 650 and 653.

(3) Steam or Heating Devices. A person may not discharge exhaust steam containing oil from any coil or other device used to heat oil either directly or indirectly onto lands adjacent to or into any surface or ground waters of the State.

(4) Records. Owners or operators shall maintain records documenting required training, inspections, tests, maintenance and repairs. Unless otherwise specified, such records must be kept on file at the facility for a minimum of three years and must be available for inspection upon the request of the Commissioner or representative of the Commissioner. In cases involving enforcement action, the three-year period for maintaining such records is automatically extended until the action is resolved.

(5) Financial Responsibility Requirements.

(a) Financial Assurance for Closure and Remediation Costs. The Commissioner requires evidence of financial assurance in the amount of at least $2 million per facility as a condition of an operating license to ensure proper closure and remediation of facilities. This evidence must accompany any new, renewal or transfer application for a marine oil terminal license. Financial assurance can be established, subject to the approval of the Commissioner, by any combination, of the following: insurance and risk retention group coverage, guarantee, surety bond, letter of credit or trust fund. In determining the adequacy of evidence of financial assurance, the Commissioner shall consider the financial mechanisms in 40 C.F.R., §§ 280.96 through 280.99 and 280.102 through 280.103 except the term “underground tank” or “UST” must be replaced with or include the addition of, “aboveground tank” or “AST”, as applicable. Any bond filed must be issued by a bonding company authorized to do business in the United States. Any guarantee must specify the relationship of the entity providing the guarantee to the licensee and applicant.

Financial instruments must also be updated when estimated costs for closure and remediation of the facility change, at license renewal, or prior to expiration dates or non-renewal of the financial instruments, and in the case of guarantee on an annual basis.

The Commissioner may require a change in the amount of financial assurance required if after a review of a preliminary closure plan and engineering assessment of probable closure and remediation costs the review indicates a change in the requirement would be appropriate.

(b) Preliminary Closure Plan. A preliminary closure plan must accompany the financial assurance instrument and must detail the approach for completing closure in accordance with Section (12)(D) of this Chapter. The plan must include an engineering assessment of probable closure costs completed in support of this Section, and that must include a detailed cost analysis of all closure and remediation actions. The engineering assessment must include:

(i) For any underground piping proposed to remain in place, a feasibility assessment for removal of underground piping in accordance with Section (12)(D)(2) of this Chapter, including the supporting rationale;

(ii) The removal of all underground piping not covered by (i) above;

(iii) The removal of all tanks and aboveground piping;

(iv) The cost for removal of all ancillary equipment such as oil water separators, transformers, additive tanks, and containment structures;

(v) The cost of an investigation into contamination from spills, releases and disposal activities that have occurred on the site;

(vi) The cost of removal of contamination and cleanup of the site for expected areas of contamination and where a discharge has occurred, such that the facility site is suitable for the most protective use level (generally residential use, although occasionally a different use has more protective levels). Where contamination is likely to discharge to surface water or ground water, the cost to clean up to applicable cleanup standards protective of surface water and ground water; and

Note: For purposes of demonstrating adequate funding in a financial assurance mechanism to fully complete closure, the preliminary closure plan and associated cost estimate is intended to be a conservative view of what actions will be necessary to complete closure. The assumptions used in arriving at the cost estimate associated with the preliminary closure plan may vary from the actual site conditions at the time of the final implementable closure plan. A preliminary closure plan is a future looking plan. The closure plan in Section (12)(D) of this Chapter is a plan that would be implemented at closure with consideration of actual site conditions at the time of closure.

(vii) A contingency amount of 25%.

The engineering assessment may not consider the salvage value for scrap metal, used equipment, additives or other wastes including waste oils. The engineering assessment must include costs for the required work to be performed by a third party.

Note: Consult *Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities,* 40 C.F.R. §264.142, Cost Estimate for Closure for assistance in conducting a cost estimate. Other documents that provide helpful information are RCRA, Superfund & EPCRA Call Center Training Module (Introduction to RCRA Financial Assurance), Items to Submit for RCRA Closure Cost Estimate, and Transmittal of Interim Guidance on Facilities Subject to RCRA Corrective Action. Each of these documents includes information on cost estimating, the types of financial instruments and other general financial guidance.

(c) Liability Insurance Requirements. Owners or operators shall maintain a minimum of $1,000,000 per occurrence and $2,000,000 annual aggregate in liability insurance exclusive of legal defense costs, for third parties to address damage to their property or personal injury. The Commissioner may require at their sole discretion, if deemed appropriate, an increase in the amount of liability insurance when taking into consideration such factors as the size and location of the facility and the proximity of neighbors and sensitive resources to the facility. Insurance policies must provide full coverage of the facility without exclusions or limitations including exclusions for self insured retention for a portion of the policy and loading or offloading exclusions. Documentation of liability insurance must be submitted with the license application, when the policy changes, and upon request of the Department. Documentation must include a certificate of insurance and the signed insurance policy in effect.

**10. Intrastate Pipelines.** This Chapter expressly adopts and incorporates by reference the regulations concerned with or related to the safety standards and accident reporting requirements for intrastate pipeline facilities used in the transportation of oil in *Transportation of Hazardous Liquids by Pipeline,* 49 C.F.R. pt. 195.

**11. Land Based Oil Terminal Facility Staff Training.**

A. Persons directly involved in the day to day operations of an oil terminal facility shall be trained and experienced in the proper operations, procedures and required maintenance of the facility, and in procedures to respond to discharges of oil. Each facility shall appoint an individual who is responsible for oil discharge prevention and accountable for any oil discharge. This individual shall schedule training sessions for operational personnel to ensure a complete understanding of the federal Spill Prevention, Control and Countermeasures (SPCC) plan, OPA 90, and any applicable contingency plan.

B. Personnel directly involved in the day to day operations of an oil terminal facility shall be trained annually on the requirements of this Chapter.

C. Upon request of the Commissioner, records must be made available indicating the titles, job descriptions, and training summaries of those employees required to receive the training found in paragraph (A) above. All training records must be maintained for a minimum of 3 years.

**12. Non-Operating Tanks and Facilities.**

**A. Facility Lockout.** When a facility is not in use or under competent supervision for a period of 7 consecutive days or longer, the gates and other access ways must be closed and locked, and the loading valves, filling and gauging pipes must be locked. All tanks, piping, equipment and other devices must be capped or blanked in a manner to prevent their use. Valves that isolate tanks, piping and equipment or that could permit a discharge must be locked in the closed position. Any dedicated electrical or hydraulic control devices serving the tank, piping or other equipment must be locked in the closed position. The owner or operator shall notify the Department at least 10 days prior to a facility lockout.

**B. Temporarily Out of Service.** Facility owners or operators shall notify the Department of storage tanks or facilities that are planned to be or have been temporarily out of service for 12 or more months. The storage tanks or facility must be temporarily closed as follows:

(1) All oil must be removed from the tank and piping system to the lowest drawoff point. Any waste oil generated from the tank or piping must be disposed of in accordance with all applicable state and federal requirements;

(2) Tanks must be protected from flotation in accordance with good engineering practices if in an area within four feet above the 100-year floodplain;

(3) All openings must be secured and locked. Fill pipes, downloading pipes and any other pipes and openings must be capped or secured to prevent access, or accidental or unauthorized use or tampering;

(4) Storage tanks or facilities that are temporarily out of service are subject to all requirements of this Chapter including, but not limited to, periodic testing, inspection, licensing and reporting requirements;

(5) Tanks or piping that are temporarily out of service for more than 2 years must be cleaned, and certified to be gas free by a marine chemist or a certified industrial hygienist. Oil and oil residue must be removed from the tank and all connecting pipes. Connecting pipes must be disconnected or blanked to ensure product is not able to be inadvertently transferred into the closed tanks or piping:

(6) A tank that has been temporarily out of service may not be reactivated for petroleum storage unless a suitability for service inspection is performed that finds the tank suitable for its intended service in accordance with *API 653*. Suitability for service inspections may only be conducted by a qualified engineer with expertise in the construction and design of field constructed aboveground storage tanks and who is a State of Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes. A report detailing the results of the inspection must be provided to the Department that is signed and sealed by the professional engineer conducting the inspection.

**C. Tanks Out of Service.** A tank or piping is out of service when it has been temporarily out of service for more than 10 years. Any tank or facility that is out of service must comply with the following:

(1) Provisions must be made for natural breathing of the tank to ensure that the tank remains vapor-free;

(2) All connecting piping must be disconnected and securely capped or plugged. All tank openings must be secured and locked;

(3) Tanks must be marked with the date of when the tank was taken out of service;

(4) Aboveground tanks must be protected from flotation in accordance with good engineering practice; and

(5) A tank that has been out of service may not be reactivated for petroleum storage unless a suitability for service inspection is performed that finds the tank suitable for its intended service in accordance with *API 653*, and a report detailing the results of the inspection is provided to the Department that is signed and sealed by the professional engineer conducting the inspection. Suitability for service inspections may only be conducted by a qualified engineer with expertise in the construction and design of field constructed aboveground storage tanks and who is a State of Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes.

**D. Facility Closure.** At total facility closure, when a licensee chooses to relinquish the facility license, or if the facility is in disrepair and out of service for more than 5 years, the owner or operator shall comply with the requirements of this Section.

Note: Examples of facilities in disrepair include, but are not limited to, those with rusted tanks and piping, holes in structures, trees growing in containment structures and within tanks, and lack of access control.

(1) The owner or operator shall prepare a written facility closure plan that meets standards for safe closure and site remediation within 60 days of the decision to close the oil terminal facility, relinquish the license or to not restore the facility into working order. The closure plan must be submitted to the Department for review and approval. The plan must include an implementation schedule that includes a realistic schedule for investigation, dismantling, and remediation of the site. Concurrent with filing the closure plan with the Department, the owner or operator shall file a copy of the closure plan with the local municipality or with the Office of County Commissioners and the Maine Land Use Planning Commission if the facility is located in an unorganized area. The plan must provide:

(a) A workplan for an investigation relying upon geoprobing, soil test pits, or other similar intrusive methods to assess the presence and areal extent of contaminated soils, sediments, and the presence of ground water and surface water contamination, if any. The investigation must include provisions to estimate the volume of contaminated soils and ground water contaminated such that the facility site, as determined by the Department, is suitable for residential use or meets the most practicable use standards for the facility site and identify areas with current or potential future surface water or ground water impacts. The plan must include a sampling plan. The sampling plan must include parameters that take into account the historic use of the facility for petroleum products and related activities. In addition to petroleum and additive constituents, the sampling plan must include laboratory analysis for total lead, lead scavengers and where applicable toxic characteristic leaching potential for lead in soils around bulk storage tanks and areas where gasoline products were stored and distributed or where other lead residuals are likely to be present. The Department may require this sampling plan to be completed prior to implementing any or all other closure steps. Pending results of the sampling plan, the Department may require further delineation as part of this early investigation.

(b) For removal of all oil and oil residuals from tanks, discharge control equipment, discharge confinement structures, containment systems, and related appurtenances;

(c) For decontamination or removal of all remaining containers, liners, bases, and soil containing or contaminated with oil or oil residuals such that the facility site, as determined by the Department, is suitable for residential use or meets the most protective use standards practicable for the facility site. Any request to remediate the site or portions of the site to a less protective use than residential or other more protective uses than residential for certain contaminants, must include a demonstration with the closure plan that identifies the residential use levels and other more protective uses that are exceeded at the property, why it is not practicable for the facility to achieve this level of protection, the location and extent of contamination proposed to be left, and how the contamination will be protected from storm events and other conditions that could move contamination to other media, areas and to other properties. The plan must also ensure that contamination will not leach or discharge contaminants to surface waters, to ground waters, or to ground waters that will discharge to surface waters;

Note: The residential use standard is not always the most protective use for certain contaminants. See Table 5 and Table 7 of the Maine Remedial Action Guidelines (2021) and the Maine Hazardous Waste Management Rules, *Identification of Hazardous Wastes*, 06-096 C.M.R. ch. 850, §3(B) and (C) for additional assistance in evaluating contaminant levels. For assistance contact the Petroleum Licensing and Corrective Action Unit at (207) 287-7688.

Note: Current use, current zoning, or restrictive covenants proposed for the property may be part of the demonstration but are not in and of themselves sufficient justification for leaving contamination on the site.

(d) For decontamination and removal of aboveground and underground tanks and piping and related appurtenances, except for the removal of underground piping where an abandonment plan in accordance with Section (12)(D)(2) below is proposed;

(e) A comprehensive piping survey that shows the location of all former, current and abandoned pipes;

(f) A schedule for completion of closure tasks; and

(g) Publication of a notice of the availability of the closure plan for public comment in a newspaper circulated in the area of the facility. Notice to the public must be given in accordance with *Rules Concerning the Processing of Applications and Other Administrative Matters,* 06-096 C.M.R. ch. 2, §14. A copy of the public notice must be provided to all abutters and to the local municipality. If the project is in an unorganized or deorganized area, a copy must be provided to the appropriate county commissioners.

(2) In lieu of removal of underground piping, the owner or operator may propose an abandonment plan for review and approval of the Commissioner. The plan must at a minimum include:

(a) A feasibility analysis for removal of underground piping. This analysis must include the rationale for non removal of piping sections including for such reasons as the piping is located beneath permanent structures, is inaccessible to heavy equipment, or is located in such a manner or is of such a great size that it is impractical to remove; and

(b) For piping that is not feasible to remove:

(i) A method for the removal of all product sludges and liquids from the piping;

(ii) A method of filling the piping with solid inert material such that the pipes will not serve as an avenue for discharges of products stored at the facility in the future and not be disturbed during storm events; and

(iii) A method for inerting and capping or plugging abandoned piping to ensure the piping does not pose a health or explosion risk to future users of the property.

(3) Complete the facility closure plan to the satisfaction of the Department including the remediating of soils, sediments, ground water and surface water to the most protective use level, such that the facility site, as determined by the Department, is suitable for residential or meets the most protective use standards practicable for the facility site. The Commissioner may require additional soil, ground water and other testing as a part of the facility closure plan or closure implementation including additional investigation to delineate the nature and extent of any contamination. A facility may not be put into non-oil or bulk terminal service without compliance with this requirement. The owner may not carry out any facility closure activities until the Commissioner has approved the facility closure plan. The Department approval must include a schedule for the completion of the closure activities.

(4) File a written facility closure report with the Department within 60 days of completion of closure activities or in accordance with an alternative timeframe as approved by the Department. The report must include a certification from an independent Maine licensed professional engineer or an engineer otherwise working in compliance with Maine’s professional regulation statutes that the facility closure was conducted in accordance with the approved facility closure plan and any approved supplements to the closure plan, and that all regulated substances have been removed or cleaned up in accordance with applicable state laws and rules including 06-096 C.M.R. ch. 600 and 38 M.R.S. §§ 542, 546, and 552-B. The report must be signed and sealed by the professional engineer making the certification.

NOTE: Pursuant to 38 M.R.S. §552-B(2)(E), the Department will post the facility closure plan as finally amended, Department approval, inspection and testing results and completion report, including the independent Maine licensed professional engineer’s certification on the Department’s public website for 5 years following the completion of the facility closure.

(5) Within 60 days of the Commissioner's acceptance of the facility closure report, or within an alternative timeframe approved by the Department, the owner or operator shall file an underground piping survey that meets the requirements of Section (12)(D)(1)(e) above with the Registry of Deeds for the county in which the facility operates.

(6) If a facility is used as a bulk terminal, it must be operated for a minimum of ten years as a bulk terminal before the facility closure requirements for cleaning and removal of tanks and piping for oil terminal facilities no longer apply. All other requirements of this Section apply at the time of closure of the oil terminal facility including the requirement to remediate sediment, soils, ground waters, and surface waters such that the facility site, as determined by the Department, is suitable for residential use or meets most protective use standard practicable for the facility site.

**E. Owner Responsibility.** When ownership of a facility, or a tank, or piping is unknown, the current property operator is responsible for proper closure of the facility.

**13. Licensing.**

**A. Oil Terminal Facility License.** An oil terminal facility may not transfer or cause to be transferred or consent to the transfer of any oil unless that oil terminal facility holds a valid license issued by the Commissioner pursuant to *Oil Discharge Prevention and Pollution Control*, 38 M.R.S. §§ 544 and 545 and this Chapter, and the facility is in compliance with all the conditions listed on that license.

**B. Probable Cost Estimate and Preliminary Facility Closure Plan.** Any application for a new oil terminal facility license or a renewal license must include an estimate of probable facility closure cost and a preliminary facility closure plan and must provide evidence of the applicant’s financial ability to satisfy these estimated costs.

**C. Liability Insurance and Documentation.** An application for a new oil terminal facility or a renewal license must include a certificate of insurance and an insurance policy in compliance with Section (9)(C)(5)(c) of this Chapter. After a facility is licensed, a current certificate of insurance and insurance policy must be provided to the Department upon request, at the expiration of any current liability certificate or policy, when changes to the policy and related certificate are made, and at renewal.

STATUTORY AUTHORITY:

38 M.R.S. §546(4)

EFFECTIVE DATE:

October 21, 1971

AMENDED:

July 12, 1973

January 15, 1974

October 1, 1974

December 21, 1977

February 8, 1978 (filed 8-10-79) – filing 79-396, Oil Prention and Pollution Control Regulations

November 7, 1999 - Except that the Effective dates for existing facilities must be as follows:

Section (7)(I) is effective February 5, 2000;

Sections (7)(E)(2), (7)(H), (7)(J)(2)(b); (8)(C)(3) (8)(C)(8) and (8)(C)(9) are effective November 7, 2000;

Section (9)(C)(1)(c) is effective November 7, 2001; and

Section (7)(E)(1), (7)(E)(5), (8)(F)(1) (8)(B)(5)(b), (8)(C)(2), (8)(C)(6), (8)(C)(7) and (8)(I) are effective November 7, 2004.

EFFECTIVE DATE (ELECTRONIC CONVERSION):

May 4, 1996

NON-SUBSTANTIVE CORRECTIONS:

April 12, 1999 – filing C-99-81 (approval September 2, 1999, filing C-99-121)

AMENDED:

November 7, 1999 -filing 99-462

CORRECTIONS:

January 13, 2000 – filing C-00-3; approval February 1, 2000, filing C-00-18

AMENDED:

March 24, 2001 – filing 2001-89; approval April 3, 2001, filing C-01-119

NON-SUBSTANTIVE CORRECTIONS:

March 16, 2004 - elimination of out-of-place underlines, filing C-04-24

AMENDED:

April 29, 2016 – definitions 2(AA, CC); changed M.R.S.A. to M.R.S., filing 2016-053

AMENDED:

June 6, 2023 – filing 2023-079, except that the effective dates for the following existing facility requirements must be:

May 31, 2025 for that portion of Section (8)(H) relating to other requirements for existing oil terminal facilities that concerns the submission of a Natural Hazard Risk Assessment referenced in Section (7)(K);

December 31, 2025 for that portion of Section (9)(C)(2)(h)(i) relating to a 10 year internal inspection frequency; and

Five years from the date of the first submittal of the Natural Hazard Risk Assessment for that part of Section (8)(H) that relates to managing 100-year precipitation events referenced in Sections (7)(E)(1) and (7)(E)(5).

# **APPENDIX A.**

# **SPECIFICATIONS AND REQUIREMENTS**

# **FOR VERTICAL GROUND WATER MONITORING WELLS.**

1. Monitoring wells must be a minimum of 2 inches in diameter.

2. The screened zone must extend at least 10 feet into the water table and at least 5 feet above the ground water surface, as determined at the time of installation; or when installed within a secondary containment liner, the base of the well screen must extend to within 6 inches of the low point of the liner.

3. The screened portion of a well outside a liner must be a minimum of 15 feet in length and must be factory slotted with a slot size of 0.010 inch.

4. Monitoring wells must be installed with a cap at the bottom of the slotted section of the well.

5. Monitoring wells must be constructed of flush joint, threaded schedule 40 PVC or other types of PVC which have equivalent or greater wall thicknesses.

6. Monitoring wells must be numbered such that all monitoring and testing results can be easily correlated to a specific monitoring well location.

7. All monitoring wells must be equipped with liquid-proof lockable caps.

8. Monitoring wells must be properly distinguished from oil piping using American Petroleum Institute recommended symbols.

9. The screened portion of the well must be surrounded by a porous medium (e.g., sand, gravel, or pea stone).

10. The outside of the well riser must be sealed to the wall of the boring using bentonite or a similar product to a depth of 1.5 feet below ground surface, or to 0.5 feet above the water table, whichever is shallower.

11. Monitoring wells which are located in traffic areas must be cut off at ground level, clearly marked, with a raised limited access cover in accordance with PEI RP100or properly protected from vehicles.

12. Any damaged monitoring well must be repaired, replaced, or properly abandoned as soon as possible after discovery of the damage.

13. Monitoring wells must be installed with a boring rig rather than a backhoe if they are not installed within a containment liner.

14. Unless required by the Department, monitoring wells within a diked area should be properly abandoned or completed in such a way to prevent oil from reaching ground water via the well should a spill occur within the diked area. Monitoring wells should be abandoned in accordance with the Guidance for Well and Boring Abandonment, Maine Department of Environmental Protection, Bureau of Remediation and Waste Management, Division of Technical Services.

15. All wells completed with a riser extending aboveground should be protected by a steel casing.

# **APPENDIX B.**

# **OIL SAMPLING AND STORAGE PROCEDURE.**

In general, sampling procedures must conform to the following procedures in the API Manual of Petroleum Measurement Standards:

Chapter 8.1, Standard Practice for Manual Sampling of Petroleum and Petroleum Products (ASTM D4057); and

Chapter 8.2, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products (ASTM D4177).

**LABELING.**

A tag or label must be attached to each collected sample. Waterproof and oil proof ink or a pencil hard enough to dent the tag must be used. The following information must be included on the label:

1. Name of the vessel

2. Home port of the vessel

3. Sample date and time

4. Name and signature of the sampler

5. Tank sampled

6. Oil type

7. Oil origin

8. Terminal

Whenever available, the following information also must be provided:

9. API specific gravity

10. Boiling point

11. Sulfur

12. Viscosity

13. Test date

14. Testing lab

15. Analyst

**STORAGE.**

Samples must be subjected to storage conditions as soon as possible. Storage must be in a dark, cool environment. The storage compartment must be secured by lock and key with access assigned to designated personnel. Samples must be stored under these conditions a minimum of (15) days. Due to the potential fire hazard, adequate ventilation and other safety precautions should be observed. Samples must be made available to the Commissioner upon request.

**APPENDIX C.**

LIST OF REFERENCE MATERIAL.

List of National Standards and Codes Citations and location where the

reference material can be obtained:

|  |  |
| --- | --- |
| **Reference** | **Location to Obtain Document** |
|  | American Petroleum Institute  1220 L Street, NW  Washington, DC 20005  [www.api.org/standards](http://www.api.org/standards) |
| API Publication1637, Using the API Color-Symbol System to Mark Equipment and Vehicles for Product Identification at Gasoline Dispensing Facilities and Distribution Terminals, 4th Edition 2020 |
| API Recommended Practice 651, Cathodic Protection of Aboveground Storage Tanks, 4th Edition, 2014 |
| API Recommended Practice 652, Lining of Aboveground Petroleum Storage Tank Bottoms, 5th Edition, 2020 |
| API Recommended Practice 1615, Installation of Underground Petroleum Storage Systems, 6th Edition R2020 |
| API Recommended Practice 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents, 8th Edition, 2015 |
| API Standard 570, Piping Inspection Code: In-service Inspection, Rating, Repair and Alteration of Piping Systems, 4th Edition, February 2016 and Addendums of May 2017 and March 2018, and Errata of April 2018 |
| API Standard 650, Welded Steel Tanks for Oil Storage, 13th Edition, 2020 and errata 1, 2021 |
| API Standard 653, Tank Inspection, Repair, Alteration and Reconstruction, including errata 1, 2020, addendum 1, 2018, and addendum 2, 2020 |
| API Standard 620, Design and Construction of Large, Welded, Low Pressure Storage Tanks, 2013, including addendum 1, 2014, addendum 2, 2018, and addendum 3, 2021 |
| ASME B31.1-2022, Power Piping | American Society of Mechanical Engineers  22 Law Drive, P.O. Box 2900  Fairfield, NJ 07007-2900 |
| ASME B31.3-2020, Process Piping |
| ASME B31.4-2019, Pipeline Transportation Systems for Liquids and Slurries |
| ASTM D4057-22, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, 2022 | American Society for Testing and Materials  100 Barr Harbor Drive  West Conshohocken, PA 19428 |
| ASTM D5747/D5747M-21, Standard Practice for Tests to Evaluate the Chemical Resistance of Geomembranes to Liquids, 2021 |
| ASTM D4177-22, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, 2022 |
| Guidance for Well and Boring Abandonment, January 7, 2009 | Department of Environmental Protection  Bureau of Remediation and Waste Management  Division of Technical Services  [www.maine.gov/dep](http://www.maine.gov/dep) |
| Sea Level Rise scenarios. MCC STS. 2020. Scientific Assessment of Climate Change and Its Effects in Maine. A Report by the Scientific and Technical Subcommittee (STS) of the Maine Climate Council (MCC) Figure 6. Augusta, Maine. August 2020 | Maine Department of Environmental Protection  28 Tyson Drive  Augusta, ME 04330 |
| IES HB-10, Lighting Applications Standards2020 | Illuminating Engineering Society  120 Wall Street, Fl 17th  New York, NY 10005 |
| NACE Standard SP 0169-2013: Control of External Corrosion on Underground or Submerged Metallic Piping systems, 2013 | NACE International (now Association for Materials Protection and Performance)  15835 Park Ten Place  Houston, Texas 77084 |
| NACE Standard SP 0193-2016-SG: External Cathodic Protection of On-Grade Carbon Steel Storage Tank Bottoms |
| NACE Standard SP 0285-2011: Corrosion Control of Underground Storage Tank Systems by Cathodic Protection, 2011 |
| NACE Standard TM0101-2012-SG: Measurement Techniques Related to Criteria for Cathodic Protection of Underground StorageTank Systems, 2012 |
| NFPA 30, Flammable and Combustible Liquids Code, 2021 | National Fire Protection Association  11 Tracy Drive  Avon, MA 02322-9910 |
| Publication #T479  Handbook of Suggested Practices for the Design and Installation of Ground-Water Monitoring Wells-EPA Document Number: EPA 1600/4-89/1034, 1991 | National Ground Water Association  601 Dempsey Road  Westerville, OH 43081 |
| PEI Recommended Practice 100, Recommended Practice for Installation of Underground Liquid Storage Systems, 2022 | Petroleum Equipment Institute  1220 L Street, NW  Washington, DC 20005 |
| PEI Recommended Practice 200, Recommended Practice for Installation of Aboveground Storage Systems for Motor Vehicle Fueling, 2019 |
| STI R892-06, Recommended Practice for Corrosion Protection of Underground Piping Networks associated with Liquid Storage and Dispensing System, January 2006 | Steel Tank Institute  570 Oakwood Road  Lake Zurich, IL 60047 |
| STI R893-06, Recommend Practice for External Corrosion Protection of Shop Fabricated Aboveground Storage Tank Floors, January 2006 |
| STI F911-93, Standard for Diked Aboveground Storage Tanks (DAST), 1993 |
| STI F921, Standard for Aboveground Tanks with Integral Secondary Containment, 2022 |
| SSPC Painting Manual, Volume 1 & 2  Volume 1: PB-01601, Good Painting Practice, 5th Edition,  Volume 2: PB-00802, Systems and Specification, 7th Edition, 2021 | The Society for Protective Coatings (now Association for Materials Protection and Performance)  15835 Park Ten Place Houston, Texas 77084 |
| *Oil Pollution Prevention,* 40 C.F.R. pt. 112: Spill Prevention Control and Countermeasures Plan (September 22, 2021) | Superintendent of Documents  P.O. Box 371954  Pittsburgh, PA 15250  <http://www.access.gpo.gov/nara/rfr/index.html> |
| *Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities,* 40 C.F.R. §264.142, Cost Estimate for Closure (September 22, 2021) |
| *Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks (UST),* 40 C.F.R. pt. 280 (September 22, 2021) |
| *Transportation of Hazardous Liquids by Pipeline*, 49 C.F.R. pt. 195 (January 1, 2023). |
| UL 80, Standard for Steel Inside Tanks for Oil-Burner Fuels and Other Combustible Liquids, September 2007 | Underwriters Laboratories  333 Pfingsten Road  Northbrook, IL 60062-2096 |
| UL 142, Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids, 2019 |
| UL 2085 Edition 2, Standard for Protected Aboveground Tanks for Flammable and Combustible Liquids-December, May 1997 |
|  |  |

**APPENDIX D.**

NATURAL HAZARDS, CLIMATE CHANGE, AND FLOOD RISK REFERENCE MATERIAL.

The following reference materials and map resources are available to assist with due diligence for any rule requirements associated with natural hazards, climate change, and flood risks. Reports, data, and maps should be reviewed for the location where a project is located to inform a license application or renewal.

**Natural Hazards and Climate Change.**

The Maine Climate Hub, hosted by the Maine Department of Environmental Protection, is acentralized climate directory of decision-support information and resources to assist with natural hazard risk assessment and planning for climate change. The directory includes scientific assessments of climate change over time in Maine and future scenarios as well as available risk assessment decision support data for temperature, precipitation, coastal and inland flooding, and changes in ocean, aquatic, and terrestrial systems.

Climate Trends & Data.

<https://www.maine.gov/dep/sustainability/climate/trends-data.html>

[Scientific Assessment of Climate Change and its Effects in Maine report (PDF)](https://climatecouncil.maine.gov/future/sites/maine.gov.future/files/inline-files/GOPIF_STS_REPORT_092320.pdf) – Prepared by the Maine Climate Council’s Scientific and Technical Subcommittee (STS), this report summarizes the impacts of climate change in Maine and how it might impact our state in the future. The report includes detailed chapters on climate, hydrology, sea level rise and storm surge, and other relevant information for risk assessment and climate change planning.

**Flood Risk Information.**

Precipitation:

The National Oceanic Atmospheric Administration (NOAA), Northeast Regional Climate Center (NRCC), United States Geological Survey (USGS), and the Maine Climate Council’s Scientific and Technical Subcommittee (STS) have developed and maintain information that can be used for due diligence. Studies and data should be retrieved for precipitation tables, distribution curves, and intensity duration and frequency graphs to look at associated rainfall totals with design storms (including the 24-hour storm, 100-year precipitation event).

Precipitation Data from Northeast Regional Climate Center

<http://precip.eas.cornell.edu/>

Precipitation Data from National Oceanic Atmospheric Administration <https://hdsc.nws.noaa.gov/hdsc/pfds/index.html>

Coastal flooding.

*Viewing the 100-year floodplain:*

In most areas of Maine, floodplains have been mapped by the Federal Emergency Management Agency (FEMA). Maps are available at most municipal offices and are also provided by the Maine Floodplain Management Program which is part of the Maine Department of Agriculture, Conservation and Forestry (under Flood Mapping Resources).

FEMA National Flood Hazard Layer & Flood Insurance Studies.

<https://www.fema.gov/flood-maps/national-flood-hazard-layer>

Maine Flood Hazard Maps.

<https://www.maine.gov/dacf/flood/mapping.shtml>

*Viewing sea level rise:*

The Maine Climate Council and Maine Geological Survey have developed and maintain reports and information on sea level rise. Sea level rise scenarios show the different amounts of sea level rise under different greenhouse gas emission scenarios (including intermediate or high emission scenarios). The amount of sea level rise can be mapped to show the different extents and depths of inundation at locations in Maine. The Maine Geological Survey provides coastal hazard map viewers that show flooding from sea level rise, storm surge, hurricanes and other hazards that can be used for planning purposes.

Sea Level Rise Scenarios

[Scientific Assessment of Climate Change and its Effects in Maine report (PDF)](https://climatecouncil.maine.gov/future/sites/maine.gov.future/files/inline-files/GOPIF_STS_REPORT_092320.pdf) – for intermediate and high emission scenarios for Maine, reference Sea Level Rise Chapter, pages 71-132.

Sea Level Rise Trend.

<https://www.maine.gov/climateplan/climate-impacts/climate-data>

Coastal Hazards

<https://www.maine.gov/dacf/mgs/hazards/coastal/index.shtml>

*Related seal level rise legislation:*

LD 1970, *An Act to Implement Agency Recommendations Relating to Sea Level Rise and Climate Resilience,* Provided Pursuant to Resolve 2021, Chapter 67 (approved April 12, 2022).

*Result of Analysis Required by 2021 Public Law, Chapter 67, Resolve, To Analyze the Impact of Sea Level Rise* (January 10, 2022). A report to the Legislature by Maine Executive Branch Agencies of the Analysis required by 2021 Public Law, Chapter 67: <https://www.maine.gov/tools/whatsnew/attach.php?id=6446306&an=1>

LD 1572, *To Analyze the Impact of Sea Level Rise*, Public Law, Chapter 67, Resolve (enacted June 16, 2021).

**Shoreline Change and Other Site Considerations:**

Coastal Sand Dune Geology Maps (Maine Geological Survey) <http://www.maine.gov/dacf/mgs/pubs/online/dunes/dunes.htm>

Coastal Bluff Maps (Maine Geological Survey)

<http://www.maine.gov/dacf/mgs/pubs/online/bluffs/bluffs.htm>

Beginning with Habitat (Maine Department of Inland Fisheries and Wildlife) <https://beginningwithhabitat.org/index.html>