PNL-3612
UC

FUEL CONSERVATION
BY THE APPLICATION OF SPILL PREVENTION
AND
FAILSAFE ENGINEERING
(A GUIDELINE MANUAL)

Prepared For

The United States
Department of Energy
Division of
Environmental and Safety Engineering

By

Pacific Northwest ~~Research~~ Laboratory
Water and Land Resources Department
Office of Marine and Environmental Engineering

J. Leslie Goodier, P.E.
Robert J. Siclari
Phyllis A. Garrity

October 30, 1980

This report was developed as a guideline
manual for industrial and federal personnel.
the project in its entirety was monitored
by Dr. John Cece, U.S. Department of
Energy, Germantown, Maryland.

Contents

~~INDEX~~

Page

Page

LIST OF ILLUSTRATIONS

LIST OF TABLES

1. EXECUTIVE SUMMARY

From a series of nationwide plant surveys dedicated to spill prevention, containment and countermeasure evaluation, coupled with spill response action activities, a need was determined for a spill prevention guideline manual.

From Federally accumulated statistics for oil and hazardous substance spills, the authors culled information on spills of hydrocarbon products. In 1978, a total of 1456 oil spills were reported compared to 1451 in 1979. The 1978 spills were more severe, however, since 7,289,163 gallons of oil were accidently discharged. In 1979, the gallons spilled was reduced to 3,663,473. These figures are derived from reported spills; it is highly possible that an equal amount was spilled and not reported. Spills effectively contained within a plant property that do not enter a navigational waterway need not be reported. Needless to say, there is a tremendous annual loss of oil products due to accidental spillage during transportation, cargo transfer, bulk storage and processing.

As an aid to plant engineers and managers, Federal workers, fire marshalls and fire and casualty insurance inspectors, the document is offered as a spill prevention guide.

The manual defines state-of-the-art spill prevention practices and automation techniques that can reduce spills caused by human error. Whenever practical, the cost of implementation is provided to aid equipment acquisition and installation budgeting. To emphasize the need for spill prevention activities, historic spills are briefly described after which remedial action is defined in an appropriate section of the manual.

The section on plant security goes into considerable depth since to date no Federal agency or trade association has provided industry with guidelines on this important phase of plant operation.

The intent of the document is to provide finger-tip reference material that can be used by interested parties in a nationwide effort to reduce loss of oil from preventable spills.

2. INTRODUCTION AND BACKGROUND

Within the past ten years there has been considerable advancement in the technologies of spill prevention, spill containment, and failsafe engineering. The Federal government through the U.S. EPA has published spill prevention criteria developed from historic spill investigations and field surveys of industrial and Federal installations. To date there has been no attempt to define and publish information that will guide plant management and engineers in the application of spill prevention and failsafe engineering. This guideline manual is intended to extend cryptic criteria statements into a "how" and "why" to do it publication.

The U.S. Department of Energy's interest in the spill prevention program stems from a desire to reduce polluting incidents which contaminate the inland and coastal waters of the U.S. However, of major concern to the Agency is the desire to materially reduce the needless loss of energy products from accidental discharges.

U.S. Coast Guard records indicate that a grand total of 17,425,864 gallons of oil and other substances was spilled in and around U.S. waters in 1978. Since this manual is dedicated to spills from onshore facilities, rather than shipwrecks, and offshore oil producing facilities, it was determined (from USCG statistics) that 7,289,163 gallons of <u>oil</u> was spilled in 1978. This was drastically reduced in 1979 when 3,663,473 gallons of oil products were known to have been spilled within the U.S. It is reasonable to assume that the reduction was brought about by recently enacted Federal regulations, coupled with an intense effort by oil handlers, processors, and users to prevent and otherwise contain oil spills. It is worthy of note that much of the oil spilled was refined product. Naturally, the more advanced the refining of crude oil progresses, the more expensive the spill becomes. The cost from exploration, recovery, transportation and processing is then lost with the product.

It is possible that this manual will eventually be due for revision to include technological advances. In this respect suggestions, comments, and even technological input is solicited from any possible source.

Additionally, unique spill prevention measures introduced in surveyed plants are recorded for the benefit of other plant facilities. Whenever practical a recommended or suggested practice is supported by a brief description of a spill incident to support and stress the need for corrective action. A wide variety of illustrations was collected from equipment suppliers for inclusion in the manual to clarify the written word. Photographic material and illustrations were provided with the full knowledge of intended use with the authority to reproduce. A thank you is due to illustration suppliers, and regrets are due to some whose illustrations were not used due to space limitations.

It is stressed that although the names of manufacturers and products are used freely, the document is not intended as an endorsement of one or any group of products.

The following tables 2-1 and 2-2 (derived from U.S. Coast Guard data) provide condensed information on the sources and causes of reported oil spills during the years 1978 and 1979. Wherever practical, the spill causes are included in the manual along with guidelines for preventing further spills from a known cause.

TABLE 2-1

U.S. Oil Spills, 1978

	NO. OF SPILLS	GALLONS SPILLED
Other Transportation Related Marine Facility:		
Tank Rupture or Leak	3	210,025
Transportation Pipeline Rupture or Leak	1	4
Dike Rupture or Leak	1	200
Other Structural Failure	3	126
Pipe Rupture or Leak	6	175
Hose Rupture or Leak	2	350
Pump Failure	3	52
Other Equipment Failure	2	66
Tank Overflow	4	93
Improper Equipment Handling or Operation	8	3,372
Other personnel Error	7	210
Intentional Discharge	1	50
Natural or Chronic Phenomenon	3	13
Unknown Cause	5	400
Total	49	215,136
Onshore Bulk Cargo Transfer:		
Tank Rupture or Leak	5	4,525,440
Transportation Pipeline Rupture or Leak	14	58,020
Dike Rupture or Leak	4	460
Other Structural Failure	6	469
Pipe Rupture or Leak	21	2,066
Hose Rupture or Leak	11	4,427
Manifold Rupture or Leak	3	2,800
Loading Arm Failure, Rupture or Leak	3	28
Valve Failure	3	12,022
Pump Failure	2	23
Flange Failure	2	1,001
Gasket Failure	9	366
Other Equipment Failure	9	13,143
Tank Overflow	11	5,446
Improper Equipment Handling or Operation	14	1,112
Intentional Discharge	3	517
Other Personnel Error	11	2,159
Railroad Accident	1	3
Natural or Chronic Phenomenon	10	10,472
Unknown Cause	10	989
Total	152	4,460,063
Onshore Fueling		
Hull Rupture or Leak	1	4
Transportation Pipeline Rupture or Leak	5	2,216
Container Lost Intact	1	20
Other Structural Failure	1	100
Pipe Rupture or Leak	7	177
Hose Rupture or Leak	1	25
Valve Failure	1	20
Pump Failure	1	500
Other Equipment Failure	1	40
Tank Overflow	1	59
Total	25	3,375

	NO. OF SPILLS	GALLONS SPILLED
Onshore Non-Bulk Cargo Transfer		
Tank Rupture or Leak	1	25
Pipe Rupture or Leak	1	50
Gasket Failure	1	1
Other Personnel Error	1	5
Total	4	81
Other Land Vehicle		
Tank Rupture or Leak	4	909
Other Structural Failure	1	2
Hose Rupture or Leak	2	60
Other Equipment Failure	1	10
Tank Overflow	2	1,650
Improper Equipment Handling or Operation	2	60
Other Personnel Error	2	29
Intentional Discharge	1	20
Railroad Accident	2	2,000
Highway Accident	3	1,052
Unknown Cause	1	5
Total	21	5,792
Rail Vehicle Liquid Bulk		
Tank Rupture or Leak	1	300
Other Structural Failure	1	200
Pipe Rupture or Leak	1	5,117
Other Equipment Failure	1	10
Railroad Accident	10	32,300
Highway Accident	1	700
Total	15	38,627
Rail Vehicle Dry Bulk		
Railroad Accident	1	20
Rail Vehicle General Cargo		
Other Structural Failure	1	500
Other Equipment Failure	1	1,000
Railroad Accident	6	29,075
Unknown Cause	2	152
Total	10	30,727
Rail Vehicle Transfer		
Valve Failure	1	300
Highway Vehicle Dry Bulk		
Tank Rupture or Leak	1	150
Other Personnel Error	1	3
Intentional Discharge	1	4,000
Railroad Accident	1	100
Highway Accident	11	8,220
Total	15	12,476

	NO. OF SPILLS	GALLONS SPILLED
Highway Vehicle Liquid Bulk		
Tank Rupture or Leak	14	43,222
Transportation Pipeline Rupture or Leak	1	50
Dike Rupture or Leak	1	3,000
Other Structural Failure	1	50
Pipe Rupture or Leak	2	310
Hose Rupture or Leak	11	725
Manifold Rupture or Leak	1	100
Valve Failure	4	4,636
Flange Failure	3	915
Gasket Failure	2	350
Other Equipment Failure	2	120
Tank Overflow	27	4,275
Railroad Accident	2	1,235
Highway Accident	93	184,484
Aircraft Accident	1	15
Unknown Cause	3	215
Total	180	255,605
Highway Vehicle General Cargo		
Tank Rupture or Leak	1	250
Other Structural Failure	1	3
Pipe Rupture or Leak	1	500
Hose Rupture or Leak	2	105
Valve Failure	1	100
Pump Failure	1	20
Tank Overflow	1	30
Railroad Accident	1	40
Highway Accident	9	675
Total	19	1,783
Highway Vehicle Passenger		
Tank Rupture or Leak	2	133
Other Equipment Failure	1	100
Tank Overflow	1	50
Intentional Discharge	1	2
Highway Accident	5	52
Aircraft Accident	1	20
Total	11	357
Other Land Transportation Facility		
Tank Rupture or Leak	2	80
Other Structural Failure	2	7,800
Pipe Rupture or Leak	3	1,301
Hose Rupture or Leak	3	126
Manifold Rupture or Leak	1	150
Loading Arm Failure, Rupture or Leak	1	500
Valve Failure	1	75
Other Equipment Failure	12	29,890
Tank Overflow	7	602
Improper Equipment Handling or Operation	4	120
Other Personnel Error	6	206
Intentional Discharge	3	2,700
Aircraft Accident	1	150
Natural or Chronic Phenomenon	2	16
Unknown Cause	26	3,664
Total	74	47,380

	NO. OF SPILLS	GALLONS SPILLED
Railway Cargo Transfer		
Pipe Rupture or Leak	1	30
Tank Overflow	1	2,200
Unknown Cause	2	1,015
Total	4	3,235
Railway Fueling Facility		
Tank Rupture or Leak	1	20,000
Pump Failure	1	20
Other Equipment Failure	3	1,299
Tank Overflow	2	1,925
Other Personnel Error	1	300
Intentional Discharge	1	200
Railroad Accident	1	50
Natural or Chronic Phenomenon	2	35
Unknown Cause	1	300
Total	13	24,129
Highway Cargo Transfer		
Tank Rupture or Leak	2	800
Valve Failure	1	200
Tank Overflow	2	100
Improper Equipment Handling or Operation	2	301
Other Personnel Error	1	2
Highway Accident	1	1,000
Total	9	2,403
Highway Fueling		
Hull Rupture or Leak	1	2,000
Tank Rupture or Leak	4	6,380
Pipe Rupture or Leak	1	10
Valve Failure	1	300
Pump Failure	1	350
Tank Overflow	6	691
Improper Equipment Handling or Operation	2	51
Other Personnel Error	1	25
Highway Accident	1	250
Total	18	10,057
Other Pipeline		
Tank Rupture or Leak	1	3
Pipe Rupture or Leak	8	10,715
Hose Rupture or Leak	3	30,564
Unknown Cause	1	3
Total	13	41,285
Onshore Pipeline		
Hull Rupture or Leak	1	8,000
Transportation Pipeline Rupture or Leak	8	29,865
Pipe Rupture or Leak	200	1,037,299
Hose Rupture or Leak	1	10
Valve Failure	4	9,520
Gasket Failure	1	200
Other Equipment Failure	3	1,008
Improper Equipment Handling or Operaton	1	20
Other Personnel Error	1	1
Intentional Discharge	2	18,200
Unknown Cause	1	15
Total	223	1,104,138

	NO. OF SPILLS	GALLONS SPILLED
Other Onshore Non-Transportation Related Facility		
Tank Rupture or Leak	13	13,645
Transportation Pipeline Rupture or Leak	3	8,027
Container Lost Intact	1	30
Other Structural Failure	5	2,223
Pipe Rupture or Leak	18	10,986
Hose Rupture or Leak	6	282
Manifold Rupture or Leak	2	1,420
Valve Failure	8	17,461
Pump Failure	4	22
Other Equipment Failure	12	2,248
Tank Overflow	17	4,012
Improper Equipment Handling or Operation	8	1,131
Other Personnel Error	9	7,176
Intentional Discharge	7	398
Railroad Accident	1	2
Natural or Chronic Pehnomenon	4	122
Unknown Cause	14	3,366
Total	132	72,551
Onshore Refinery		
Transportation Pipeline Rupture or Leak	1	200
Dike Rupture or Leak	1	2
Other Structural Failure	1	1,000
Pipe Rupture or Leak	2	11
Hose Rupture or Leak	1	2
Valve Failure	1	2
Pump Failure	1	12
Gasket Failure	2	105
Other Equipment Failure	9	454
Tank Overflow	3	2,053
Improper Equipment Handling or Operation	4	287
Intentional Discharge	1	3
Natural or Chronic Phenomenon	2	31
Unknown Cause	5	105
Total	34	4,267
Onshore Bulk Storage Facility		
Tank Rupture or Leak	7	20,750
Transportation Pipeline Rupture or Leak	3	135
Other Structural Failure	1	100
Pipe Rupture or Leak	7	836
Hose Rupture or Leak	1	4,200
Manifold Rupture or Leak	4	831
Loading Arm Failure, Rupture or Leak	3	10,922
Valve Failure	11	30,213
Pump Failure	3	251,265
Gasket Failure	1	1,000
Other Equipment Failure	15	16,046
Tank Overflow	36	167,641
Improper Equipment Handling or Operation	5	30,343
Other Personnel Error	5	13,540
Intentional Discharge	4	1,780
Railroad Accident	1	500
Highway Accident	1	200
Natural or Chronic Phenomenon	5	2,634
Unknown Cause	4	14,100
Total	117	567,036

	NO. OF SPILLS	GALLONS SPILLED
Onshore Industrial Plant or Processing Facility		
Tank Rupture or Leak	6	17,400
Dike Rupture or Leak	5	1,420
Container Lost Intact	1	22
Other Structural Failure	6	100,381
Pipe Rupture or Leak	17	26,505
Hose Rupture or Leak	2	20
Valve Failure	11	6,801
Pump Failure	5	137
Flange Failure	1	50
Gasket Failure	2	600
Other Equipment Failure	88	20,772
Tank Overflow	21	9,299
Improper Equipment Handling or Operation	15	9,547
Other Personnel Error	12	4,498
Intentional Discharge	5	120,485
Railroad Accident	1	1,400
Natural or Chronic Phenomenon	5	415
Unknown Cause	18	592
Total	221	320,344
Onshore Oil or Gas Production Facility		
Tank Rupture or Leak	3	3,310
Dike Rupture or Leak	3	1,368
Other Structural Failure	1	1
Pipe Rupture or Leak	7	1,270
Hose Rupture or Leak	2	200
Valve Failure	3	1,880
Other Equipment Failure	6	32,742
Tank Overflow	3	1,240
Intentional Discharge	3	2,318
Unknown Cause	1	200
Total	32	44,529
Power Plant		
Tank Rupture or Leak	1	20
Transportation Pipeline Rupture or Leak	3	605
Dike Rupture or Leak	1	15
Other Structural Failure	1	40
Pipe Rupture or Leak	6	830
Hose Rupture or Leak	2	25
Valve Failure	1	5
Pump Failure	1	2
Gasket Failure	3	260
Other Equipment Failure	11	9,321
Tank Overflow	3	703
Improper Equipment Handling or Operation	4	14
Other Personnel Error	5	129
Intentional Discharge	1	30
Natural or Chronic Phenomenon	1	3
Unknown Cause	4	295
Total	48	12,297
Pipeline Within Non-Transportation Related System		
Tank Rupture or Leak	1	200
Other Structural Failure	1	10
Pipe Rupture or Leak	5	8,780
Valve Failure	2	16
Other Equipment Failure	1	50
Improper Equipment Handling or Operation	2	1,505
Other Personnel Error	3	130
Natural or Chronic Phenomenon	1	10
Unknown Cause	1	550
Total	17	11,251

TABLE 2-2

U.S. Oil Spills - 1979

	NO. OF SPILLS	GALLONS SPILLED
Other Transportation Related Marine Facility		
Hull Rupture or Leak	1	42
Tank Rupture or Leak	2	65
Transportation Pipeline Rupture or Leak	1	3
Other Structural Failure	3	57
Pipe Rupture or Leak	6	69
Hose Rupture or Leak	4	1,557
Valve Failure	1	400
Pump Failure	2	700
Gasket Failure	1	1
Other Equipment Failure	4	234
Tank Overflow	5	131
Improper Equipment Handling or Operation	6	45
Other Personnel Error	10	142
Intentional Discharge	3	251
Aircraft Accident	1	10
Natural or Chronic Phenomenon	1	5
Unknown Cause	4	207
Total	55	3,919
Onshore Bulk Cargo Transfer		
Hull Rupture or Leak	2	13
Tank Rupture or Leak	1	150
Transportation Pipeline Rupture or Leak	9	18,467
Container Lost Intact	3	9,000
Other Structural Failure	8	111,067
Pipe Rupture or Leak	16	4,116
Hose Rupture or Leak	16	657
Manifold Rupture or Leak	1	200
Loading Arm Failure, Rupture or Leak	6	791
Valve Failure	12	3,301
Pump Failure	1	60
Flange Failure	4	212
Gasket Failure	9	12,688
Other Equipment Failure	5	36
Tank Overflow	9	6,062
Improper Equipment Handling or Operation	12	6,040
Other Personnel Error	12	154
Intentional Discharge	2	505
Highway Accident	1	100
Natural or Chronic Phenomenon	5	216
Unknown Cause	3	22
Total	137	173,857
Onshore Fueling		
Tank Rupture or Leak	3	515
Transportation Pipeline Rupture or Leak	4	10,227
Other Structural Failure	2	29
Pipe Rupture or Leak	8	529
Hose Rupture or Leak	7	434
Valve Failure	1	50
Pump Failure	1	1
Flange Failure	2	22
Gasket Failure	4	82
Other Equipment Failure	3	311
Tank Overflow	3	55
Improper Equipment Handling or Operation	4	104
Other Personnel Error	5	1,204
Intentional Discharge	3	1,024
Natural or Chronic Phenomenon	1	125
Unknown Cause	1	1
Total	52	14,713

	NO. OF SPILLS	GALLONS SPILLED
Onshore Bulk Storage Facility		
Tanks Rupture or Leak	3	7,843
Transportation Pipeline Rupture or Leak	3	30,025
Container Lost Intact	2	601
Other Structural Failure	1	5
Pipe Rupture or Leak	3	162
Hose Rupture or Leak	4	601
Valve Failure	4	35,848
Pump Failure	1	700
Flange Failure	1	100
Gasket Failure	1	2,878
Other Equipment Failure	11	60,690
Tank Overflow	25	10,357
Improper Equipment Handling or Operation	6	5,170
Other Personnel Error	5	807
Intentional Discharge	17	147,814
Natural or Chronic Phenomenon	7	2,978
Unknown Cause	2	1,510
Total	96	308,089
Onshore Industrial Plant or Processing Facility		
Tank Rupture or Leak	5	2,150
Other Structural Failure	3	257
Pipe Rupture or Leak	8	2,316
Hose Rupture or Leak	5	31
Valve Failure	2	2,075
Pump Failure	4	485
Flange Failure	1	1
Gasket Failure	4	372
Other Equipment Failure	26	14,832
Tank Overflow	20	16,987
Improper Equipment Handling or Operation	9	957
Other Personnel Error	8	193
Intentional Discharge	9	19,957
Natural or Chronic Phenomenon	6	2,799
Unknown Cause	25	9,263
Total	135	72,675
Onshore Oil or Gas Production Facility		
Transportation Pipeline Rupture or Leak	2	11
Other Structural Failure	5	482
Pipe Rupture or Leak	23	21,171
Hose Rupture or Leak	10	413
Loading Arm Failure, Rupture or Leak	1	42
Valve Failure	2	44
Pump Failure	2	521
Other Equipment Failure	4	157
Tank Overflow	4	115
Other Personnel Error	2	35
Highway Accident	3	4,920
Aircraft Accident	1	4,000
Natural or Chronic Phenomenon	2	19
Unknown Cause	4	2,780
Total	65	34,710

	NO. OF SPILLS	GALLONS SPILLED
Other Pipeline		
Transportation Pipeline Rupture or Leak	1	300
Other Structural Failure	1	1,000
Pipe Rupture or Leak	12	5,495
Hose Rupture or Leak	2	51
Tank Overflow	2	600
Intentional Discharge	1	20
Natural or Chronic Phenomenon	1	20
Unknown Cause	1	84
Total	21	7,570
Onshore Pipeline		
Transportation Pipeline Rupture or Leak	13	393,526
Other Structural Failure	1	20
Pipe Rupture or Leak	227	1,672,368
Loading Arm Failure, Rupture or Leak	3	43
Valve Failure	5	1,639
Flange Failure	3	90
Gasket Failure	5	9,443
OtherEquipment Failure	4	2,335
Tank Overflow	1	150
Improper Equipment Handling or Operation	6	10,023
Other Personnel Error	1	42
Intentional Discharge	3	1,596
Natural or Chronic Phenomenon	5	5,660
Unknown Cause	3	13,160
Total	280	2,110,095
Other Onshore Non-Transportation Related Facility		
Tank Rupture or Leak	11	30,185
Dike Rupture or Leak	1	210
Container Lost Intact	1	1,800
Other Structural Failure	8	10,114
Pipe Rupture or Leak	5	776
Hose Rupture or Leak	1	1
Valve Failure	4	26
Pump Failure	1	200
Gasket Failure	2	4,600
Other Equipment Failure	25	8,167
Tank Overflow	13	2,080
Improper Equipment Handling or Operation	13	4,341
Other Personnel Error	17	1,773
Intentional Discharge	10	3,327
Highway Accident	1	3,450
Natural or Chronic Phenomenon	8	1,690
Unknown Cause	7	675
Total	128	100,388
Onshore Refinery		
Tank Rupture or Leak	1	7,000
Transportation Pipeline Rupture or Leak	2	1,360
Other Structural Failure	3	12,090
Pipe Rupture or Leak	4	640
Valve Failure	3	8,610
Gasket Failure	1	80
Other Equipment Failure	2	210
Tank Overflow	2	10,001
Other Personnel Error	2	94
Natural or Chronic Phenomenon	2	500
Unknown Factor	1	1
Total	22	40,536

	NO. OF SPILLS	GALLONS SPILLED
Other Land Transportation Facility		
Hull Rupture or Leak	1	35
Tank Rupture or Leak	2	4,100
Other Structural Failure	3	16
Pipe Rupture or Leak	7	24,623
Hose Rupture or Leak	2	1,025
Manifold Rupture or Leak	1	800
Valve Failure	1	5
Other Equipment Failure	5	80
Tank Overflow	10	2,816
Improper Equipment Handling or Operation	3	23
Other Personnel Error	8	2,118
Intentional Discharge	7	11,596
Highway Accident	1	40
Aircraft Accident	1	450
Natural or Chronic Phenomenon	6	438
Unknown Cause	6	1,031
Total	64	49,196
Railway Cargo Transfer		
Other Structural Failure	1	1
Pipe Rupture or Leak	1	3
Valve Failure	1	250
Tank Overflow	1	2
Natural or Chronic Phenomenon	1	50
Total	5	306
Railway Fueling Facility		
Other Equipment Failure	1	10
Tank Overflow	1	2
Improper Equipment Handling or Operation	1	2,000
Intentional Discharge	1	32,460
Unknown Cause	2	40
Total	6	34,512
Highway Cargo Transfer		
Tank Rupture or Leak	2	115
Hose Rupture or Leak	1	1
Pump Failure	1	50
Tank Overflow	4	1,155
Improper Equipment Handling or Operation	1	50
Other Personnel Error	1	1,000
Intentional Discharge	1	1,800
Total	11	4,171
Highway Fueling		
Tank Rupture or Leak	6	4,395
Pipe Rupture or Leak	5	2,064
Hose Rupture or Leak	1	10
Pump Failure	1	50
Tank Overflow	5	505
Improper Equipment Handling or Operation	2	371
Other Personnel Error	3	260
Highway Accident	2	350
Unknown Cause	1	300
Total	26	8,305

	NO. OF SPILLS	GALLONS SPILLED
Highway Vehicle Liquid Bulk		
Tank Rupture or Leak	9	33,250
Transportation Pipeline Rupture or Leak	1	2
Other Structural Failure	3	240
Pipe Rupture or Leak	5	2,590
Hose Rupture or Leak	12	632
Manifold Rupture or Leak	1	1
Valve Failure	5	2,590
Pump Failure	2	2,193
Gasket Failure	4	1,210
Other Equipment Failure	3	7,175
Tank Overflow	19	11,075
Improper Equipment Handling or Operation	7	302
Other Personnel Error	6	876
Intentional Discharge	4	156
Highway Accident	71	189,125
Aircraft Accident	5	12,120
Natural or Chronic Phenomenon	1	10
Unknown Cause	5	255
Total	163	263,802
Highway Vehicle Dry Bulk		
Tank Rupture or Leak	2	52
Railroad Accident	1	10
Highway Accident	5	190
Total	8	252
Highway Vehicle General Cargo		
Tank Rupture or Leak	2	90
Transportation Pipeline or Leak	1	10
Container Lost Intact	1	120
Hose Rupture or Leak	1	20
Improper Equipment Handling or Operation	1	30
Other Personnel Error	2	15
Highway Accident	13	849
Aircraft Accident	1	100
Unknown Cause	1	1
Total	23	1,135
Highway Vehicle Passenger		
Tank Rupture or Leak	3	517
Other Equipment Failure	2	30
Improper Equipment Handling or Operation	1	2
Other Personnel Error	1	1
Intentional Discharge	2	2
Highway Accident	5	140
Unknown Cause	1	1
Total	15	693
Unknown Type of Land Vehicle		
Tank Overflow	4	450
Railroad Accident	1	2,500
Highway Accident	5	8,649
Total	10	11,599

	NO. OF SPILLS	GALLONS SPILLED
Onshore Non-Bulk Cargo Transfer		
Tank Rupture or Leak	1	400
Hose Rupture or Leak	1	15
Gasket Failure	1	210,000
Improper Equipment Handling or Operation	1	2
Other Personnel Error	1	300
Total	5	210,717
Other Land Vehicle		
Tank Rupture or Leak	3	2,000
Pipe Rupture or Leak	1	70
Hose Rupture or Leak	4	49
Tank Overflow	2	930
Improper Equipment Handling or Operation	3	4,780
Intentional Discharge	2	65
Railroad Accident	1	10,000
Highway Accident	5	1,657
Aircraft Accident	1	10
Natural or Chronic Pehnomenon	1	10
Unknown Cause	4	436
Total	27	20,007
Rail Vehicle Liquid Bulk		
Tank Rupture or Leak	1	1,000
Other Equipment Failure	2	30,150
Tank Overflow	1	2,000
Railroad Accident	10	61,170
Natural or Chronic Phenomenon	1	2,000
Total	15	96,329
Rail Vehicle General Cargo		
Flange Failure	1	1,000
Railroad Accident	5	3,480
Highway Accident	1	500
Unknown Cause	1	4,000
Total	8	8,980
Rail Vehicle Transfer		
Tank Rupture or Leak	1	800
Hose Rupture or Leak	1	1,800
Railroad Accident	2	4,225
Total	4	6,825

	NO. OF SPILLS	GALLONS SPILLED
Power Plant		
Tank Rupture or Leak	1	10,000
Transportation Pipeline Rupture or Leak	1	5
Dike Rupture or Leak	1	40
Other Structural Failure	3	703
Pipe Rupture or Leak	8	2,142
Loading Arm Failure, Rupture or Leak	1	10
Valve Failure	9	1,875
Pump Failure	2	7
Flange Failure	1	50
Gasket Failure	1	30
Other Equipment Failure	7	270
Improper Equipment Handling or Operation	4	18,022
Other Personnel Error	6	113
Natural or Chronic Phenomenon	2	2
Unknown Cause	4	585
Total	51	33,854
Pipeline Within Non-Transportation Related Facility		
Other Structural Failure	1	51
Pipe Rupture or Leak	11	43,447
Hose Rupture or Leak	1	5
Gasket Failure	1	700
Other Equipment Failure	1	1
Other Personnel Error	1	2,000
Intentional Discharge	1	3
Unknown Cause	2	30
Total	19	46,238

3.0 FACILITY LAYOUT AND PLANNING

3.1 General

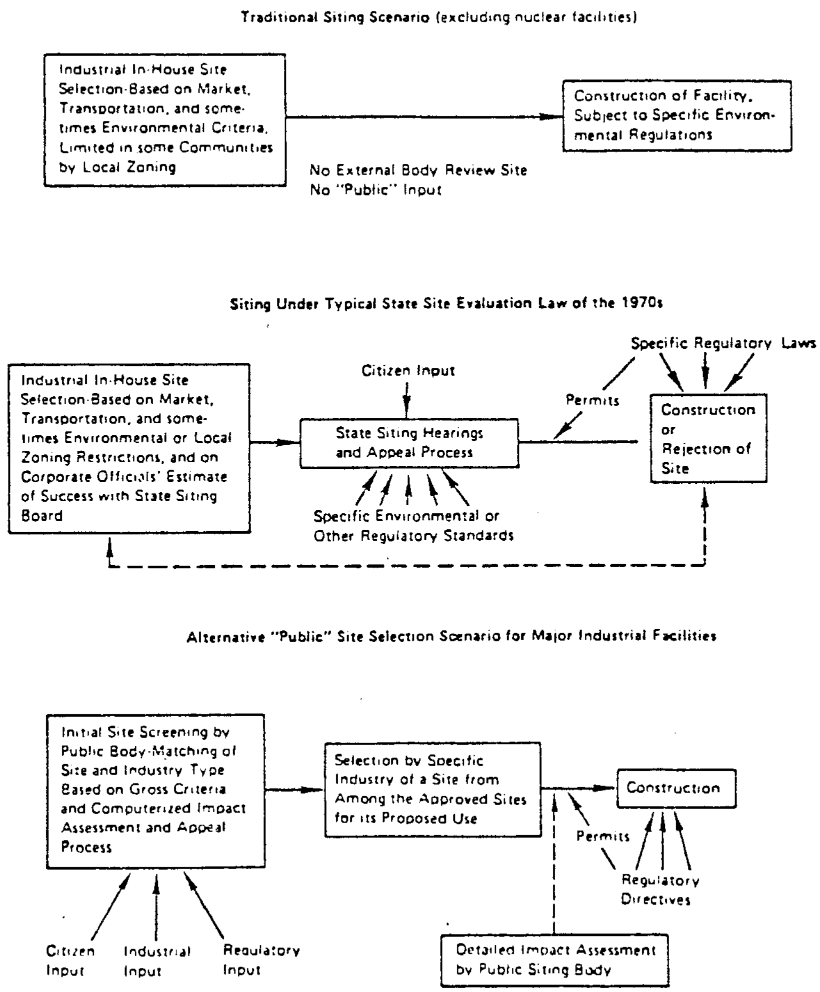
Site selection has become an increasing difficult factor since the advent of the era of environmental concern. Numerous objections are raised when potential sites are studied in highly populated and industrial areas. Whereas workers selected to live as close to the plant as possible, this is no longer the case. When sites are selected in isolated areas, the conservation of virgin territory becomes a predominant factor. Attempts to gain authority to construct a marine terminal on the Southeast coast (right or wrong) has resulted in an expediture of $12 million just to overcome environmental objections and legal injunctions.

There is a dire need for a new industry to consider such factors as access to the labor market and raw materials, access to the product markets and transportation facilities, and the availability of adequate energy sources. An additional condition of considerable importance is the accessibility to waste disposal facilities. The waste transportation and disposal sources should have federally issued permits to handle the wastes generated in the production process.

The site planners must satisfy the federal and local governments and the general public that socioeconomic goals are met and that the natural ecosystems and microenvironments will be fully protected from plant operations from raw material through to finished product.

One noticeable European trend is to develop industrialized port facilities that eliminate the transportation of raw materials into the hinterland and finished products back to the shipment center. Within the U.S. there are indications that the European trend is extending to the coastal areas.

Figure 3-1 provides an insight into three decisional approaches to site selection.



SOURCE: D. Stever, U.S. Department of Justice, Washington, D.C.

<u>FIGURE 3-1</u>.

Three Decisional Approaches
to
Site Selection

3.2 Bulk Storage Tank Siting

The environmental and economic exposures developed from the design of bulk storage tank facilities warrant special consideration.

The trend toward "jumbo" storage tanks of 500,000 barrel capacity (79,000 m^3) and even more has created loss potentials equal to those of many new process units. A 500,000 barrel tank filled with crude at early 1980 prices of $25/barrel would have a content value of $12,500,000. The loss of a bulk container can increase this figure to $15,000,000.

A past loss incident involved two 120,000 barrel (19,000 m^3) floating roof tanks within common diking. The common diking was a major factor in their destruction and the loss of over 50,000 barrels (8,000 m^3) of gasoline. A third 120,000 barrel (19,000 m^3) tanks some 85 feet (26 m) away in a separate dike suffered only light fire damage to its upper shell. Incidents such as this give basis for considering separate diking of each storage tank.

Wide spacing between tanks and between tank fields and processing locations is most advisable. Radiant heat damage is possible to closely adjacent tanks even when they fail to ignite. Tank spacings should be at least equal to the diameter of the largest tank.

Large storage tanks containing flammable products should be located at least 500 to 1000 feet (150 to 300 m) from plant processing units. As far as practical, tanks should be installed on level ground; they should never be located uphill from other tanks or processing facilities.

3.2.1 Protection Against the Elements

Site selection warrants indepth investigation into potential flooding and the susceptibility to damage from hurricanes, earthquake, or tidal wave. On the Texas Gulf Coast, wind action and a high tidal action caused flooding in a plant normally protected from high water by a flood control dike. All electric motors at grade level were damaged and had to be rewound, many with replacement of bearings and almost 40 percent with replacement of motors. Remedial action after this expensive learning process resulted in motors, pumps, etc. being raised above the flood's high water mark.

Also on the Texas Coast under flood and high winds, the contents of waste treatment ponds were washed away and partially full product tanks floated off their foundation. Bulk storage tanks in the most recent Johnstown, Pennsylvania flood also floated clear of their foundation.

Since oil supply demands bulk storage to be available at locations on the Gulf of Mexico, weight alone should not be considerated as a suitable means of anchorage. With adequate warning it may also be advisable to fill tanks with water, contamination being more desirable to tank damage and possible loss of the content.

Earthquakes present a number of unsurmountable problems that depend on the severity of the tremor or tremors. Structures in earthquake prove locations are generally designed to resist the dynamic forces of earthquakes by use of equivalent static loads. The later being gained from historic experience. In most areas local building codes demand such designs. Basically, foundations become a major design factor. No structural design system is adequate unless it transmits all forces acting upon it into adequate support in the ground.

3.3 Old Sites

Older plants suffer greatly from space problems. The frontage is normally bound by an access roadway with adjacent plants on either side. They generally back up to a waterway. This situation restricts the ability to provide or increase spill containment systems. Therefore, special environmental management procedures are demanded.

At many product transfer locations, especially tank car loading racks, overfills have saturated the earth surrounding the railroad tracks. It was also a standard procedure to drain the residue from tank cars directly onto the tracks prior to a product change. Past sins are now causes of serious plant problems. Ground water contamination has occurred at many locations. At other facilities, the spilled material is continually leaching out to the shoreline to develop a sheen that can be most predominant during periods of low tide. It is common to find wells drilled down to ground water along a shoreline or even in the center of a plant. These are not water wells but wells used to recover oil spilt over many years of operation.

In an attempt to terminate the problem, one Baltimore, Maryland plant dug a deep trench and filled it with impermeable clay to control lateral flow of spilled product and contain same on the plant property.

Dual drainage systems have also been constructed--one to direct surface water from "clean areas" out to a direct discharge and the second to service "dirty areas", such as bulk storage and processing locations. Surface water from these "dirty areas" is directed through concrete lined trenches (generally covered to prevent the entry of debris) to wastewater treatment facilities or oil and water separation systems. Plants lacking space to treat wastewater to the stage now demanded by Federal law have, for a fee, connected the discharge into municipally operated wastewater treatment plants.

In many "dirty water" drainage systems, oil spill retainment sumps have become state-of-the-art. Figure 3.1 shows a design suggested by the Manufacturing Chemists Association.

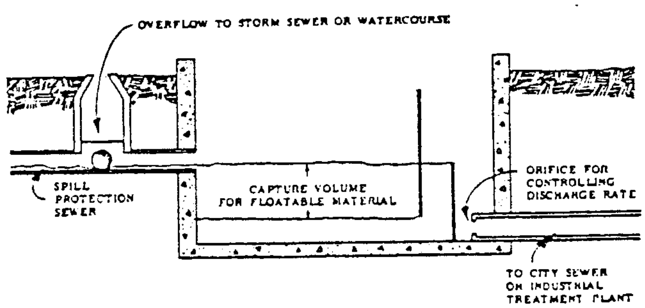


FIGURE 3-2.

Spill Material (Floatable) Containment Sump
(From MCA (CMA) Guidelines)

3.4 New Sites

Once the problems of obtaining a permit to construct a new hydrocarbon processing or distribution facility have been overcome. New facilities have a number of operational advantages over "old sites." The new technologies can be incorporated into plant design. Space problems should be eliminated. Modern drainage and waste treatment facilities can be provided with monitoring systems at strategic locations to detect any flow that deviates from the normal. Newly erected tanks can be coated to retard internal corrosion. Vapor collection systems can be installed to reduce the fire and explosion hazards and to reduce the odors normally associated with handling hydrocarbon products. In short, some or all of the items contained in this guideline manual can be introduced in the facility.

References:

1. "Long Range Environmental Outlook." Proceedings of a National Academy of Sciences Workship.

2. Tank Farms--Loss Prevention and Protection. Bulletin 6805M. Industrial Risk Insurers.

4. BULK STORAGE TANKS

4.1 General

Spills of hydrocarbon products from bulk storage tanks can generally be attributed to the following causes:

- Tank overfill during the filling process whereby oil is released to the environment through the tank's roof-mounted venting system. At some time or another most tanks have been subjected to an overfill and the evidence can be viewed by product streakage down the side of the tank. Following a recent overfill, pools of product can be viewed within the diked or otherwise spill restrained area.

- Loss of product during water drainage procedure. Night and day temperature changes result in a buildup of condensate water within the inner surfaces of the storage tank. This can be further complicated with water contained in the product during transfer from a ship, barge or other transportation vehicle. Floating roof tanks that have worn seals can also accumulate rainwater. A similar situation exists for fixed roof tanks having badly corroded heads. Overflights over bulk storage tank fields will quickly indicate that the latter water contamination source is not an isolated condition. The water, being heavier than the hydrocarbon product, collects in the lower reaches of the vessel specifically the tank bottom.

Most organizations draw the accumulated water from the tank on a regular cycle to reduce internal corrosion, and to avoid product contamination. Water draining can be a lengthy procedure, dictated largely by the size of the storage vessel, and the humidity associated with the geographical area. Unless careful monitoring is exercised massive quantities of product can be drained from the tank when the water and oil interface is reached. One marketing terminal in Massachusetts spilled 250,000 gallons of #2 Fuel Oil when a tank attendant forgot to close the water draw valve during a draining procedure. This oil escaped into a navigable waterway through a partially opened rain water drain valve within the tank's diked enclosure.

- Complete tank failure is not a common occurrence although a major spill in Europe resulted from failure of a new tank during its first filling. The tidal wave of product washed away an earthen dike releasing the spilled material into a heavily traveled canal system serving a number of countries. Cleanup contractors from all over Europe were needed to mitigate the spill.

- Minor leaks from tank seams and corroded openings are common. Visual examination of any large tank field will provide rapid proof of this spill source. There are still many riveted seam tanks in service at both industrial and federal storage facilities. Riveted seams and riveted heads are quite prone to leakage, especially the lowermost seal to bottom seam connection which can which can stand in rainwater during periods of heavy rain.

- Tank bottoms are subject to extensive corrosive deterioration and many storage tanks will require tank bottom replacement during their operating life. The detrimental effects of bottom head and even shell plate corrosion depends upon its rate of penetration. Corrosion affecting large areas of steel plate is not so likely to penetrate the metal as rapidly as localized corrosion on small areas.

  Localized corrosion may be in the form of pitting. The pits result from the formation of "rust blisters" which eat into the metal. The resulting pits can be as small as a pinhead or as large as a half dollar. They may be widely scattered or so close that a honeycomb surface results. Obviously, scattered pitting does not weaken the metal to the extent of closely spaced pitting.

Riveted seams are also exposed to metal deterioration from "grooving." This is a form of deterioration which eats into the steel plate parallel to an overlapped seam. It results from a combination of stress concentration and localized corrosion. Dished heads at their attachment to a tank shell are also subject to this form of metal deterioration. Since the defect occurs at locations subjected to stress concentration it can result in failure unless detected and suitably repaired by welding.

There is no doubt that lower head failure, due to metal deterioration, can result in extensive spills that could go undetected for a lengthy period of time. The leakage could continue until it seeped out from under the tank foundation or until a low liquid level alarm was activated.

- Another potential overfill source, which also results in product contamination, is a worn seal on a floating roof tank. The worn seal permits the entry of rain water into a tank. Frequently water drains can become frozen shut with ice resulting in heavy accumulations of water on the tank top. One USN fueling station experienced a problem with drifting snow that collected on one side of the tank top causing the entire floating roof to tip displacing the jet fuel content.

- Another source of total loss of a tank's content can be attributed to tank support failure. Horizontal storage tanks supported by masonary supporting walls have been exposed to total failure of one support. Total loss of product has been experienced at three known locations where the unsupported end of the tank ruptured upon impact with the earth and in one case, a poured concrete foundation.

4.2 Corrosion Control

This is one of the main approaches to spill prevention from metal tanks. In recent years there have been great advances in the development of synthetic paints and coatings to combat corrosive deterioration on steel surfaces. The protective coatings are of excellent quality and durability if applied over properly prepared surfaces. It has been quite common practice throughout the petroleum industry to leave steel surfaces unpainted for at least a year. This action permits some rusting of the steel to occur in the form of minor pitting. Additionally, this has been an accepted method of removing mill scale from steel plate and pipe without any extensive labor. The initial rusting roughens the steel surface thereby increasing the cohesion factor of the protective coating. Many plants continue to operate in the described manner.

The National Association of Corrosion Engineers (NACE) has, however, conducted extensive investigations and suggests that steel surface preparation can best be accomplished by abrasive blast cleaning or through the medium of water blasting prior to coating or recoating.

4.2.1 Abrasive Blast Cleaning

The NACE Technical Committee assigned to abrasive blasting investigations reported ". . . the blast cleaning method of surface preparation is a relatively simple procedure having only two end components: the abrasive and its velocity. . . ." There is, however, an ever increasing wide range of abrasives and the selection of the right abrasive is most important to gain the best maximum result.

The size of the abrasive should range between 20 to 30 mesh as most abrasives recommended for surface preparation are used in these sizes. When cleaning tank surfaces it is extremely rare that the abrasive can be recycled and reused economically. Under these circumstances the following abrasives are recommended for general blast cleaning where the abrasives cannot be economically reclaimed:

- Silica Abrasives
- Slag Sand
- Slag Shot
- Flint Abrasives

The cleaned surface should, according to the National Association of Corrosion Engineers (NACE), be cleaned to one of the following standards:

<u>12.3.1 NACE No. 1 White Metal Blast Cleaned Surface Finish</u>: Defined as a surface with a gray-white (uniform metallic) color, slightly roughened to form a suitable anchor pattern for coatings. This surface is free of all oil, grease, dirt, mill scale, rust, corrosion products, oxides, paint, and other foreign matter (comparable to SSPC-SP 5-63, White Metal Blast Cleaning).

<u>12.3.2 NACE No. 2 Near-White Blast Cleaned Surface Finish</u>: Defined as a surface from which all oil, grease, dirt, mill scale, rust, corrosion products, oxides, paint, or other foreign matter have been removed except for light shadows, streaks, or slight discolorations (of oxide bonded with metal). At least 95% of any given surface area has the appearance of NACE No. 1, and the remainder of that area is limited to slight discolorations (comparable to SSPC-SP 10-63T, Near-White Blast Cleaning).

12.3.3 NACE No. 3 Commercial Blast Cleaned Surface Finish: Defined as a surface from which all oil, grease, dirt, rust scale, and foreign matter have been completely removed and all rust, mill scale, and old paint have been removed except for slight shadows, streaks, or discolorations caused by rust stain or mill scale oxide binder. At least two-thirds of the surface area shall be free of all visible residues, and the remainder shall be limited to light discoloration, slight staining, or light residues mentioned above. If the surface is pitted, slight residues of rust or paint are found in the bottom of pits (comparable to SSPC-SP 6-63, Commercial Blast Cleaning).

12.3.4 NACE No. 4 Brush-Off Blast Cleaned Surface Finish: Defined as a surface from which oil, grease, dirt, loose rust scale, loose mill scale, and loose paint are removed, but tightly adhering mill scale, rust, paint, and coatings are permitted to remain if they have been exposed to the abrasive blast pattern, so that numerous flecks of the underlying metal are uniformly distributed over the entire surface.

The quality and durability of the protective coating to be applied over the cleaned metal surface is very dependent on the cleanliness of the metal. In consideration of this fact, NACE No. 1 and No. 2 surface finishes are recommended.

The cost of abrasive blast cleaning is a geographical variable. In the New England area blast cleaning, according to one contractor, costs in the vicinity of $1.50/sq. ft. In the Washington, D.C. area a tank cleaning organization reports that a first class blast cleaning followed by a single application of "Glass Armor"* cost $20,000 for a 50,000 gallon capacity fuel tank.

4.2.2 Water Blast Cleaning

The NACE reports that water blasting is well suited for cleaning steel and other hard surfaces in instances when sandblasting is not feasible. In essence blast cleaning is preferable if it can be possibly used. Because water blasting has no abrasive effect on steel or other hard surfaces it does not provide an anchor pattern for coating adhesion, its use is recommended primarily for maintenance painting programs.

It should be indicated, however, that sand can generally be introduced into the water stream if a more thorough cleaning is desired. This in effect introduces a wet sand

---

*A product of Bridgeport Chemical Corporation, Pompano Beach, Florida.

blasting technique which aids in dust control but develops muddy conditions at grade level.

Actually, conventional wet sand blasting requires heavy duty compressors to develop the cleaning force and large mixing tanks to store the sand and water mix. This has in recent years been circumvented by the development of water spray fingers which surround the sand discharge nozzle to "wet" the sand in jet suspension. The water supply is connected into an annular collar from which it enters the water supply "fingers" to mix with the dry sand some 3 in. forward of the sand outlet. This design effectively controls dust generation and heavy-duty compressors/pumps are not required.

Water blasting usually removes anything that is not tightly adhered to the surface and is an effective technique for cleaning irregularly shaped surfaces such as valves, flanges, back-to-back angles, grating and floor plates.

The following tables, 4-1 and 4-2, taken verbatim from NACE publication "Surface Preparation of Steel and Other Hard Materials By Water Blasting Prior to Coating or Recoating," provides data on cleaning time for coated and uncoated steel.

The equipment used for cleaning consists of a trailer mounted high pressure pump driven by gasoline, diesel, electric or air motors or engines. The units can be

TABLE 4-1 – Range of Time Required to Water Blast Uncoated Steel* (Square Feet Per Hour)

Structural Classification	Conditions 1	2	3	4	5	6	7
A	300-500	175-350	150-300	100-200	75-150	200-400	75-150
B	450-600	325-450	275-400	150-300	100-225	350-500	100-225
C	500-800	375-625	300-525	200-450	125-375	400-700	125-375
D	600-800	450-725	400-600	250-550	150-450	500-800	150-450
E	150-400	90-275	80-250	50-150	25-100	200-400	75-150

Structural Classification of Fabricated Items Including Structural Steel and Piping

A – Small size members having less than 1 square foot per lineal foot.
B – Medium size members having 1-3 square feet per lineal foot.
C – Members having greater than 3 square feet per lineal foot.
D – Flat surfaces such as vessels, tanks, checker plate, floors, and undersides of floor plates, etc.
E – Gratings.

Surface Condition

1. Mud and loose foreign matter (Note: waterblasting will not remove adherent mill scale).
2. 10% of surface covered with rust, loose scale, and loose foreign matter.
3. 30% of surface covered with rust, loose scale, and loose foreign matter.
4. 60% of surface covered with tightly adhering hard rust and pitting.
5. Greater than 60% of surface covered with tightly adhering rust and pitting.
6. Very light coating of oil and grease. No corrosion present.

Note: If corrosion exists on 6 and 7 (under the oil and grease), classify by the appropriate condition 2 through 5 above.

*All data are based on actual experience. The production was less in some isolated cases and greater in others. General conditions, environment, accessibility to work area, personnel protection, and equipment protection requirements will exert some influence on the time required.

TABLE 4-2 – Range of Time Required to Water Blast Coated Steel* (Square Feet Per Hour)

Structural Classification	Conditions 1	2	3	4	5	6	7	8
A	200-400	175-350	150-300	100-200	75-150	200-400	75-150	5-25
B	350-500	325-450	275-400	150-300	100-225	350-500	100-225	5-30
C	400-700	375-625	300-525	200-450	125-375	400-700	125-375	10-30
D	500-800	450-725	400-600	350-550	150-450	500-800	150-450	12-40
E	100-300	90-275	80-250	50-150	25-100	200-400	75-150	5-25

Structural Classification of Fabricated Items Including Structural Steel and Piping

A – Small size members having less than 1 square foot per lineal foot.
B – Medium size members having 1-3 square feet per lineal foot.
C – Members having greater than 3 square feet per lineal foot.
D – Flat surfaces such as vessels, tanks, checker plate, floors, and undersides of floor plates, etc.
E – Gratings.

Surface Condition

1. Finish coat of paint weathered thin; paint has chalked; a very minor amount of contaminants and other foreign matter present; and no corrosion of substrate.
2. Finish coat of paint weathered thin and some primer showing. 10% of surface covered with rust, loose scale, and loose paint film.
3. Finish coat of paint thoroughly weathered, and considerable primer shows. Approximately 30% of surface covered with paint, rust, and corrosion scale. Some surface pitting and paint blistering.
4. Finish coat of paint thoroughly weathered with almost all primer showing. Approximately 60% of surface covered with tightly adhering rust. Some surface pitting and paint blistering.
5. Finish coat of paint and most primer completely worn off. Most of surface covered with hard rust and pitting.
6. Very light coating of oil and grease.
7. Heavy coating of oil and grease.
8. Asphalt mastic and coal tar coatings to be removed between 1/32 and 1/4 inch thickness.

*All data are based on actual experience. The production was less in some isolated cases and greater in others. General conditions, environment, accessibility to work area, personnel protection, and equipment protection requirements will exert some influence on the time required.

operated at pressures that range from 2000 to 10,000 psi. Experience has shown that for most practical purposes a pressure range from 2500 to 5000 psi is adequate. Pressures above 5000 psi constitute a hazard because they are difficult to handle and place undue stress and strain on the operator.

Detergents and other cleaning chemicals and hot or cold water can be used to suit a particular application. However, the cleaning agents must be removed from surface prior to the application of a protective coating.

For cleaning most ferrous metal rust inhibitors are injected at the nozzle or at the water supply to prevent oxidation of bare metal.

Water blasting techniques are similar to those of sandblasting. The nozzle is normally held six to ten inches from the surface being cleaned. In some instances a distance of two to three feet may achieve the desired cleaning action. The best nozzle angle for cleaning purposes can be readily detected by trial and error use, although for brittle substances such as dead paint or rust scale the nozzle normally is held perpendicular to the surface.

4.2.3 Surface Coating - General

It is normal to coat the complete interior of a bulk storage or production vessel. However, in the petroleum production industry coatings are sometimes restricted to the following areas:

- The bottom of the tank and 18 inches up to the wall of the shell (including pumps, striker plates and exterior drain lines). This is the area where corrosive water collects which has separated from the hydrocarbon product. This can be accumulations of condensate, or water that has mixed with the product during transportation or at other periods of production or storage. The water is normally drawn off through specially designed "water drain valves" which are described later in this report.
- The underside of the tank roof and 18 inches down the wall of the shell. This practice is exercised if hydrogen sulfide bearing crude or condensate is to be stored or oxygen is not excluded.

It is known that some 90 percent of the U.S. tanker fleet now have the interior of the cargo compartments "epoxy" coated, there appears no inventory available to determine the percentage of on land tanks that have been treated.

4.2.4 Coating Procedures and Products

Bulk storage tanks are most commonly constructed of iron and steel for reasons of strength, hardness, durability and cost control. The major limitations to iron and steel tanks are weight and the vulnerability to corrosion and rusting.

To prepare a metal surface for the application of a corrosive resistant coating the metal must first be cleaned of any contaminant that will interfere with the full development of adhesion of the protective paint and coating systems. Most coatings adhere properly when surface "anchor patterns" are developed by sandblasting.

For optimum adhesion or mechanical bonding an anchor pattern of between one and two mils in depth is required. The depth of the anchor pattern is controlled mainly by the selection of the abrasive and the pressure applied to the cleaning process.

Glidden Coating and Resins Division of SCM Corporation describes other cleaning systems that are alternate to sandblasting as follows:

- Water Washing - This method is used for removing water soluble chemicals or foreign material. Care must be taken to prevent extended contact of the water with the iron or steel surface since this may result in rust formation.

- Steam Cleaning - Steam cleaning is usually accomplished with a "Steam Jenny." The "Jenny" may use steam alone or in combination with cleaning compounds or detergents. Cleaning compound residue should be rinsed from the surface with water following steam cleaning. Steam cleaning is effective for removing oils, greases, and various water soluble chemicals.
- Weathering - Natural weathering is often used as one of the most economical methods of removing mill scale, dislodging it by the development of rust. Negatively, poor appearance prevails during the weathering period and heavy rust must be removed before applying finishes.
- Solvent Cleaning - Solvents such as mineral spirits, xylol, tuluol, etc., may be used to remove greases or similar solvent soluble foreign materials from the surface of the iron or steel. If rags are used for the application of these solvents, they should be changed periodically to avoid accumulation of oils or greases in cloths and redeposit on the metal surface.

  Solvents may also be used in vapor degreasing units. This method avoids the redeposit of oils and greases on new metal surfaces being cleaned. The solvents used in such cases are usually those with nonflammable characteristics such as perchlorethylene.

- Flame Cleaning - Flame cleaning is often used to dislodge foreign particles or mill scale on the surface of hot rolled steel. Due to differences in expansion and contraction of the mill scale as compared to the steel substrate, the mill scale is broken loose by playing a very hot flame over the surface.

- Acid Cleaning or "Pickling" - This type of surface preparation is usually done in shops, not in the field. Acid cleaning, properly controlled, will remove mill scale and foreign materials while producing a very fine anchor pattern. Thorough rinsing of the surface after pickling is necessary to remove all traces of the acid, the presence of which may adversely affect the adhesion and performance of protective coatings.

- Hand Tool Cleaning - This is a mechanical method of surface preparation involving wire brushing, scraping, chipping and sanding. It is not the most desirable method of surface preparation, but can be used for mild exposure conditions. Optimum performances of protective coatings systems should not be expected when hand tool cleaning is employed.

- Power Tool Cleaning - This mechanical method of surface preparation is widely used in industry and involves the use of power sanders or wire brushes, power chipping hammers, abrasive grinding wheels, needle guns, etc. Although usually more effective than hand tool cleaning it is not considered adequate for use under severe exposure conditions or for immersion applications.

Naturally for newly-constructed or existing tanks of large dimension and capacity abrasive blast cleaning develops a cleaner surface, is not as labor intensive as other processes, and generally is the cheaper cleaning process.

U.S. paint manufacturers produce a wide range of coatings that includes the following generic types:

Alkyd
Bituminous
Epoxy
Latex
Oil Base
Polyurethane
Silicone

The most commonly used coating, however, for the interior painting of bulk liquid storage tanks, is coal tar epoxy. This is a rugged and strongly adherent industrial coating, highly resistant to chemicals, water, abrasion, and corrosion. The coating generally consists of a combination of a coal tar epoxy resin base and a polyamide curing agent. It can be obtained in measured containers (4 gallons of base and one gallon of curing agent per 5-gallon unit). The unit is mixed prior to application and when applied it possesses high film building properties. However, an 8.0 mil. dry coating provides desirable coverage. A typical cost per gallon is in the vicinity of $10.00 Unlike most protective coatings coal tar epoxy requires no special primers for most applications. Its limitations are that it should not be used for prolong contact with strongly oxidizing chemicals, dilute alkalies, ketones, esters, alcohols, or for lining tanks used to store "white" petroleum products.

The coating can be applied by brush, roller, or spray. Two coats are recommended for best results in chemical and immersion service and up to 20 hours of drying time is suggested between coats. Coverage is about 155 sq. ft/gal. at 10.5 mils wet, 8.0 mils dry. Xylol is recommended for cleanup and equipment cleaning.

Another product used for lining bulk storage tanks is "Glass Armor" a product of Bridgeport Chemical Corporation, Pompano Beach, FL. This organization contends that the product actually builds a new tank inside an existing tank and that one-quarter of a million tanks have been Glass Armored, over the past 22 years. The material is a specially designed formulation of thermosetting epoxy resins. The epoxy is formed by mixing a bright blue resin material with a white material known as the "activator."

One bucket mixed together covers approximately 40 square feet of tank surface. The manufacturer says this allows for a coating about 3/16 in. thick. An indirect-fired heater is used for curing which cures the coating in a relatively short period of time.

Once the tank is cured, a "sparking machine" is used to check for any leaks or missed spots in the coating. Since the epoxy does not conduct electricity, the spark tester is run over the walls of the tank and where a spark appears a "holiday" is found. Repairs are made with a quick drying epoxy. This protective process is provided by a nationwide group of franchised applicators.

Another state-of-the-art product is known as "Glassflake" produced by Glassflake International, Inc., Jacksonville, FL 32223. This material has been used extensively on marine applications, on ship's decks, tank interiors, above water hull surfaces (freeboard), riveted strakes, sea chests, stern frame and rudders. According to the manufacturer it is resistant to a variety of acids, organics, and salts as listed in the following table (4-3).

Glassflake is claimed to have the following advantages and features:

- Corrosion. Coating provides a solid barrier 20 mils or more thick with minimal permeability against vapor particles that cause corrosion.
- Erosion. Glassflake has excellent resistance to erosion. It fills pits and cavities in old steel to extend the service life before plate replacement.
- Electrolysis. In cavitation areas, a significant reduction in the number of sacrificial metal anodes can be made.
- Abrasion. The effect of mechanical damage to the hard, solid coating is minimized and confined, without undercutting or loss of adhesion to the surrounding area.
- Easily Repaired. The coating can be easily repaired in case of heavy damage by cleaning the damaged area and feathering edges of surrounding coating, then recoating to maintain a long-lasting coating protection.

TABLE 4-3
APPROVED CHEMICAL ENVIRONMENTS
FOR GLASSFLAKE COATINGS*

ENVIRONMENT	% BY WEIGHT	MAXIMUM TEMPERATURE LIMITATION 70°F.	150°F.	200°F.
Hydrochloric Acid	to 10%	R	R	R
	10 to 38%	R	R	NR
Phosphoric Acid	to 85%	R	R	R
Sulphuric Acid	to 50%	R	R	R
Sulphuric	50 to 70%	R	R	(to 160°F)
Sea Water		R	R	R
Distilled Water		R	R	NR
Mineral Oil	—	R	R	R
Vegetable Oils	—	R	R	R
Animal Fats	—	R	R	R
Calcium Hypochlorite	to 20%	R	R	NR
Sodium Hypochlorite	to 15%	R	R	NR
Chlorine Water, Sat'd.	—	R	R	R
ORGANICS				
Asphalt(uncut)		R	R	—
Crude Oil--sour		R	R	—
Crude Oil—sweet		R	R	—
Furnance Oil		R	R	—
Gasoline		R	R	—
Kerosene		R	R	—
SALTS				
Aluminum Chloride	100%	R	R	—
Aluminum Nitrate	to 10%	R	R	—
Aluminum Sulphate	100%	R	R	—
Ammonium Chloride	100%	R	R	—
Ammonium Nitrate	to 83%	R	R	(to 170°F)
Ammonium Sulphate	to 25%	R	R	—
Barium Carbonate	100%	R	R	—
Barium Chloride	100%	R	R	—
Calcium Sulphate	100%	R	R	—
Copper Chloride	100%	R	R	—
Ferric Chloride	100%	R	R	R
Ferric Nitrate	100%	R	R	—
Ferrous Chloride	100%	R	R	—
Ferrous Sulphate	100%	R	R	—
Lead Acetate	100%	R	R	—
Magnesium Carbonate	100%	R	R	—
Magnesium Chloride	100%	R	R	—
Magnesium Sulphate	100%	R	R	—
Potassium Alum	100%	R	R	—
Potassium Chloride	100%	R	R	—
Potassium Dichromate	100% (No HF)	R	R	—
Potassium Nitrate	100%	R	R	—
Potassium Sulphate	100%	R	R	—
Silver Nitrate	100%	R	R	—
Sodium Bicarbonate	100%	R	NR	NR
Sodium Bisulphate	100%	R	NR	NR
Sodium Carbonate	to 5%	R	R	(to 180°)
	to 25%	R	(to 120°F)	NR
Sodium Chloride	100%	R	R	R
Sodium Ferrocyanide	100%	R	R	—
Tridodium Phosphate	to 5%	R	R	—
Zinc Chloride	100%	R	R	—
Zinc Sulphate	100%	R	R	—

NOTE: R--Recommended for Service
NR--Not recommended for Service
— -Inadequate information available for a recommendation; or, inapplicable.

While recommended for use as indicated, conditions vary to such an extent from job to job that the foregoing is not to be taken as a representation or warranty that the coating will in all cases perform as indicated.

*Table developed by manufacturer

- Three Colors. Glassflake coating is available in three colors--white, marine grey (especially recommended for decks) and black.
- Non-Skid Finish.* A non-skid finish is available for deck coatings, in which sand is added to the resin at time of application.
- Can Be Machined. The Glassflake coating can be machined with conventional metal working tools, which permits the repair of pumps and valves for extended service life. Can be applied in any thickness desired without cracking or crazing.

The material consists of glass flake particles of approximately 1/8 in. diameter, 2 to 3 microns thick, in a 100% solids resin polyester resin vehicle. There are no solvents to evaporate. Polymerization of the resin vehicle at the time of application makes the coating hard, solid and of minimum permeability. There are normally about 130 overlapping layers of the flakes to make a continuous surface that is a minimum of 30 mils thickness.

The coating can be applied by plant maintenance personnel under the direct and constant supervision of a Glassflake field engineer. All materials and application equipment are furnished by the Glassflake engineer.

*This type of finish may also be well suited to tank tops.

The metal surface is first sandblasted to a white finish, after which a Glassflake primer is applied to prevent surface oxidation before the coating is applied. The Glassflake is then sprayed (or on small surfaces, troweled) onto the metal surface while another employee immediately rolls the coating to orient the flakes before the resin starts to dry. The coating presently (5/80) costs $3.96/lb. for the Glassflake and coating material (sprayed coverage 1/2 lb per sq. ft.), $3.90/lb. for the catalyst (used 2-3% by weight to the glass and the resin), and $1.50/lb. for the styrene modifer (mix three gallons modifier/ per gallon of curative catalyst) which is also used as a cleaning agent. Figures 4-1, 4-2, and 4-3 depict application techniques for the Glassflake coating.

Another generally accepted coating is Glidden Coatings and Resins Division of SCM Corporation "Glid Guard". This organization recommends a 3 mil (dry) primer coat of Glid Guard Y5251 with Y5252 activator or curing agent applied over a sandblasted finish. This would be followed by <u>two</u> applications of Glid Guard Epoxy Chemical Resistant Finish Y5240 mixed with Y5242 curing agent in equal proportion. Once mixed the coating material is left to gel for about 30 minutes following which it can be applied for a period of about 8 hours (depending on heat of day). All mediums of application can be used -- spray, brush, etc. Once completed the coating would be in the vicinity of 9 mil dry.

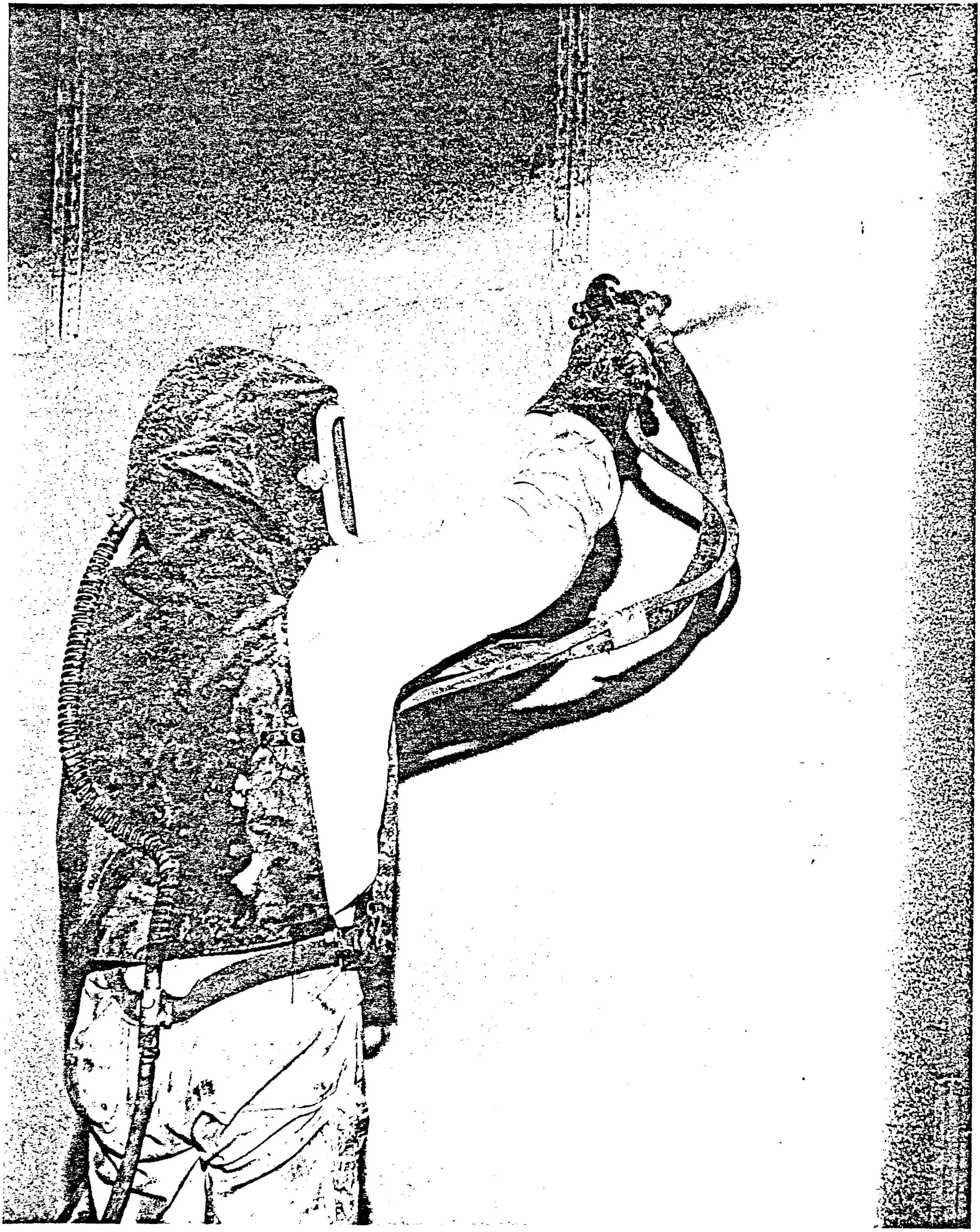


FIGURE 4-1. Spray application of Glassflake Type GF-202 to tank wall interior.

FIGURE 4-2. Application of Glassflake Type 202.
Finish brushing to insure penetration into holes, etc. and to orient glassflakes in resin, thus providing laminar matrix and maximum resistance to vapor penetration and abrasion.
(Photograph Courtesy of Glassflake International)

FIGURE 4-3. Application of Glassflake GF-202 to Tank Floor Using Pole Gun. (Glassflake Inter-

One gallon of the mix will coat 350 square feet and the cost of the primer and finish coat is comparable being about $17.78 for the epoxy finish and $16.27 for the curing agent. In AZ, CA, NM, MT, ID, NV, OR, UT, WA, Al and HI the cost is increased by about 20¢ per gallon.

Woolsey Marine Industries Inc. produces a coating under the trade name "Res-N-Glas." This is a polyester resin vehicle containing 120 layers of 3-micron thick glass flakes which self-laminate into a 30 mil 98% solids coating. It is pre-catalyzed and sprayed over the bare metal surface with conventional high capacity spray equipment. No special technique is required; just a simple cross-path spray action. The material is claimed to be corrosion, abrasion, and impact resistant and is compatible with cathodic protection systems. Coverage is in the vicinity of 52 sq. feet per gallon at 30 mils thickness. At 77°F the regular cure is hard in 4 hours and full cured in one week.

Koppers Company Inc. has developed a wide range of protective coatings. The following table provides basic data on their range of coatings. (Table 4-4)

As an additional aid toward the selection of a protective coating, the following tables are reproduced from the paper "How To Evaluate Urethane Coatings" by J. A. Cross as published in the October 22, 1979 issue of "Chemical Engineering." (Tables 4-5 and 4-6).

TABLE 4-4
Koppers Company Inc. Protective Coatings

	(1) 6060-5 Isophthalic Polyester Laminate	(1) 980 Series Gel Coat Off-White	Bitumastic No. 300-M	(2) Koppers Inorganic Zinc No. 701	(3) Bitumastic Non-Drying Tank Bottom Coating	(4) Koppers 200 HB Epoxy
Number of coats	Laminate	Multi-pass	2	1	1	1
Theoretical Coverage (1 gallon) 1.0 mils dry film thickness	1,604	1500	1,184	640	1,344	603
Film build ratio Minimum dry film required Wet film required	90 (entire laminate) Not applicable	15 18	8-10 10-14	2.0-3.0 5-7	125 mils (⅛") 149 mils	6.0 13.8
Sq. foot coverage to achieve minimum film	18	60-80	90-115	257	8	90
Temperature limitations Dry Wet	225° F 160° F	200° F N/A	250° F 120° F	800° F 100° F	110° F 100° F	200° F 100° F
Drying Curing Time at 70° F and 50% relative humidity To Touch To Recoat	2 hrs. curing time usually required to reach Barcol Hardness of 30 with 1% MEKP catalyst	20 min 1 hr. (dry hard)	3-4 hrs 24 hrs	15 minutes Overnight to 24 hrs.	2 hrs. - semi-drying material	4 hrs Overnight
Primer	P-527	N/A	Koppers 654 Epoxy Primer	N/A	N/A	Koppers Inorganic Zinc No. 701
Thinner	Styrene	Styrene	Koppers Thinner 2000	Koppers Thinner 442	Koppers Thinner 1000	Koppers Thinner 10,000
Cleaner	Acetone	Acetone	Koppers Cleaner 2300	Koppers Thinner 442	Koppers Thinner 1000	Koppers Cleaner 2300

	(5) Koppers 1122B Linear Polyurethane	(5) Koppers 1515 Silicone Alkyd	(6) P-527 Strontium Chromate Epoxy Primer	(7) Koppers 654 Epoxy Primer	(8) Koppers 622 Rust-Penetrating Primer
Number of coats	2	2	1	1	1
Theoretical Coverage (1 gallon) 1.0 mils dry film thickness	675	704	460	718	792
Film build ratio Minimum dry film required Wet film required	1.0 2.4	1.5 3.5	1.6 2.8	1.5 3.4	1.5 3.0
Sq. foot coverage to achieve minimum film	540	375	230	385	425
Temperature limitations Dry Wet	150° F N/A	250° F N/A	250° F 100° F	250° F 100° F	250° F N/A
Drying Curing Time at 70° F and 50% relative humidity To Touch To Recoat	1 hr. ½ hr. to 24 hrs.	2 hrs 18 hrs.	1 hr 2 hrs. to overnight	1 hr Overnight	2 hrs 48 hrs
Primer	Koppers 654 Epoxy Primer	Koppers 622 Rust Penetrating Primer	N/A	N/A	N/A
Thinner	Koppers 1184 Thinner	Koppers Thinner 4000	Koppers Thinner 10,000	Koppers Thinner 10,000	Koppers Thinner 4000
Cleaner	Koppers 1184 Thinner	Koppers Thinner 4000	Koppers Thinner 10,000	Koppers Cleaner 2300	Koppers Thinner 4000

(1) Pit fillers, fiberglass strips for tank bottoms

(2) Steel coating general

(3) Applied on tank bottom between foundation

(4) Used primarily for JP Fuel tanks

(5) Tank exterior coating

(6) Primer for 6060-5 Isophthalic Polyester Laminate

(7) Primer for 300 M Coal Tar Epoxy

(8) Primer for 1515 Silicone Alkyd

TABLE 4-5

Properties of eleven different industrial coatings

	*Gloss retention	Weathering	Abrasion	Heat	Water	Salts	Solvents	Alkalis	Acids
Vinyl	6	10	8	6	10	10	5	9	10
Vinyl acrylic	8	10	8	6	9	9	4	8	9
Epoxy polyamide	3	8	9	8	9	10	8	10	8
Water-base epoxy	3	8	8	6	8	8	8	7	7
Aliphatic urethane	10	10	10	8	[illegible]	10	8	10	10
Chlorinated rubber	6	7	7	5	10	10	3	9	9
Coal-tar epoxy	5	7	9	7	10	10	4	8	10
Acrylic	9	9	8	6	9	9	4	7	7
Industrial acrylic emulsion	7	8	6	5	8	7	2	6	6
Silicone alkyd	9	9	6	7	8	8	4	4	6
Alkyd	6	8	6	7	8	8	4	4	5

Ratings: 10 Excellent
9-8 Good
7-6 Fair
5-1 Poor

*Gloss retention based on Southern Florida exposures.

TABLE 4-6

Chemical resistance of urethane and epoxy coatings

Acids	Aliphatic urethane	Polyester epoxy	Urethane epoxy	Urethane-modified lacquer
10% HCl	Pass	Pass	Soft	Soft
10% H_3PO_4	Pass	Pass	Soft	Soft
10% CH_3COOH	Pass	Pass	Soft	Soft
10% HNO_3	Slight yellow	Soft	Soft	Failed
10% H_2SO_4	Pass	Pass	Pass	Failed
Caustics				
10% KOH	Pass	Pass	Pass	Failed
10% NaOH	Pass	Pass	Pass	Failed
Household NH_3	Slight yellow	Soft	Slight yellow	Failed
Solvents				
Toluol	Pass	Pass	Pass	Failed
MEK	Pass	Pass	Slight soft	Failed
Butanol	Pass	Pass	Slight soft	Failed

Reproduced from "How To Evaluate Urethane Coatings", Written By J. A. Cross, Chemical Engineering 10/22/79

4.2.5 Flexi-Liners

An additional technique for corrosion control and tank protection of the inner surface of a storage tank has been developed by the Flexi-Liner Corporation, Pasadena, CA 91102. The organization manufacturers balloon-like containers which are tailor-made to suit tank size. The flexi-liner is produced with built-in connections and manholes. They can be installed in welded, riveted or bolted metal tanks. The supplier claims that the liner is easy to install and tank preparation such as sand blasting is not required. Unskilled labor can readily install the liner which is suspended from the top of the tank. Bonding is not required and the patented process of liner installation is suitable for any vertical, horizontal, or rectangular tank, with or without tops.

Liners fabricated from any of fifteen different materials are available to contain the following products:

Acetic acid	Chromic Acid	Nitric Acid
Alcohol	Fatty Acids	Paper Mill Liquors
Alum	Formal-dehyde	Phenol
Amines	Glycerine	Phosphoric Acid
Ammonium Nitrate	Glycols	Stoddard Solvent
ASTE oils	Hexane	Sulphuric Acid
Bleach	Hydrochloric Acid	Turpentine
Caustic	Muriatic Acid	Vegetable Oil

Almost all plating solutions and combinations of chemicals can be accomodated. Liners have been produced for tanks having two million gallon capacity. Figure 4-4 indicates the procedures for installing a Flexi-Liner in an existing storage tank.

An additional advantage of this type of inner liner results from the fact that there is no deteriorated metal to product contact. This eliminates contamination of the tank's contents.

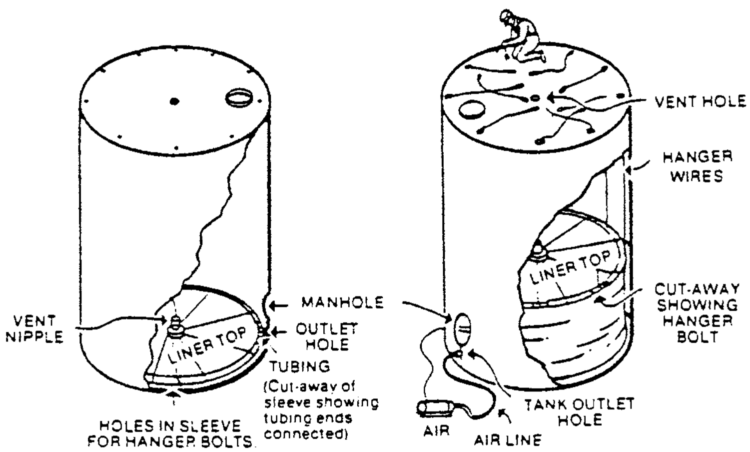


FIGURE 4-4. Procedure for Installing Flexi-Liner Into Existing Storage Tank Photograph Courtesy Flexi-Liner Corp.

4.3 Tank Shell Thickness Testing

Many industrial facilities have conducted shell thickness testing of bulk storage tanks for many years. There has, however, been a decided increase in this preventive maintenance procedure over the past ten years. There are three known testing procedures presently in use.

- Visual Examination - during regular internal tank cleaning (generally every five years). By this process vulnerable tank surfaces are visually examined for metal deterioration, measurements are taken with a depth gage equipped with a micrometer screw head. The depth of deterioration is then related to the original plate thickness as shown on the mill specification sheets. Records are maintained and the rate of plate deterioration is determined.
- Drill and Weld - with this technique the shell or head plate is drilled and measured with a micrometer or vernier caliper, after which the drilled hole is filled with weld metal. Records are maintained in line with visual examination.
- Nondestructive Testing - there are at least three organizations that manufacture ultrasonic thickness measurement devices. Ultrasonic sound is used to penetrate the shell and measure the metal thickness. The result is graphically depicted on a range scale or a lighted crystal display (LCD). Measurement ranges from 0.050 in. to 25 in. are obtainable.

The following manufacturers can provide a range of thickness testing devices:

Automation Industries, Inc./Sperry Products Division
Danbury, CT 06810

Model UTM-24* ($1900.00) is a lightweight pocket size instrument designed to measure thickness of steel from 0.06 in. to 4 in. This is a four place, battery powered unit with automated decimal location.

Model UTM-20* duplicates Model UTM-24 in cost and operation but has three place metric readout. Figures 4-5 and 4-6 depict the UTM-24 unit.

Model NOVA-21 ($1950.00) gages metal, glass and most plastics in a range of 0.005 in. to 25 in. It has inch and metric readout and has either battery or AC energy source. The cables and transducer for this unit increases the price by an additional $250.00.

UJ Reflectoscope with digital thickness gage ($5717.00 plus $250.00 for cables and transducer) is a dual purpose unit that detects flaws in metal and can gage thicknesses from 0.010 in. to 19.99 (0.25 mm to 199.9 mm). Readout presentation is both video and digital.

---

*The manufacturer is in the process of replacing these units with a Models UTM-100 and UTM-200 which are smaller and more accurate and easier to use (information supplied by letter 7/7/80).

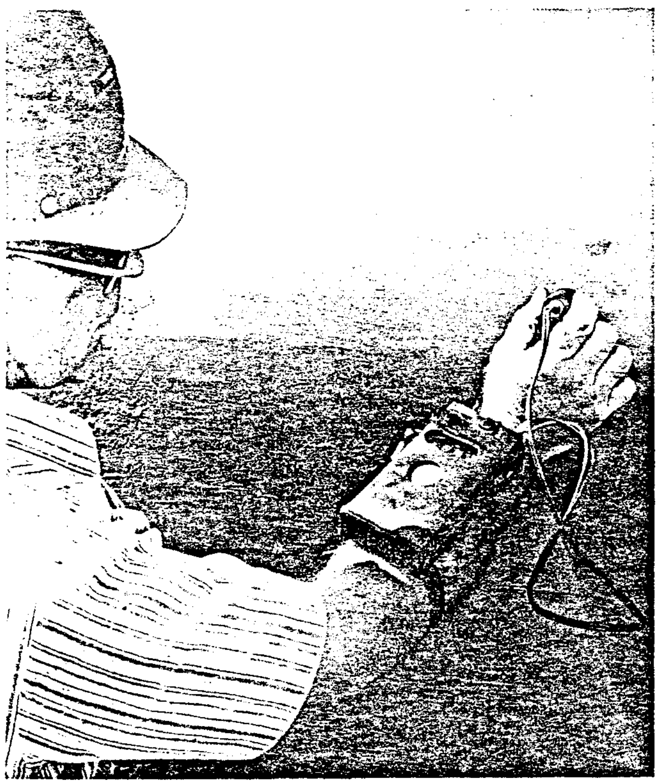


FIGURE 4-5. Model UTM-24 Thickness Tester

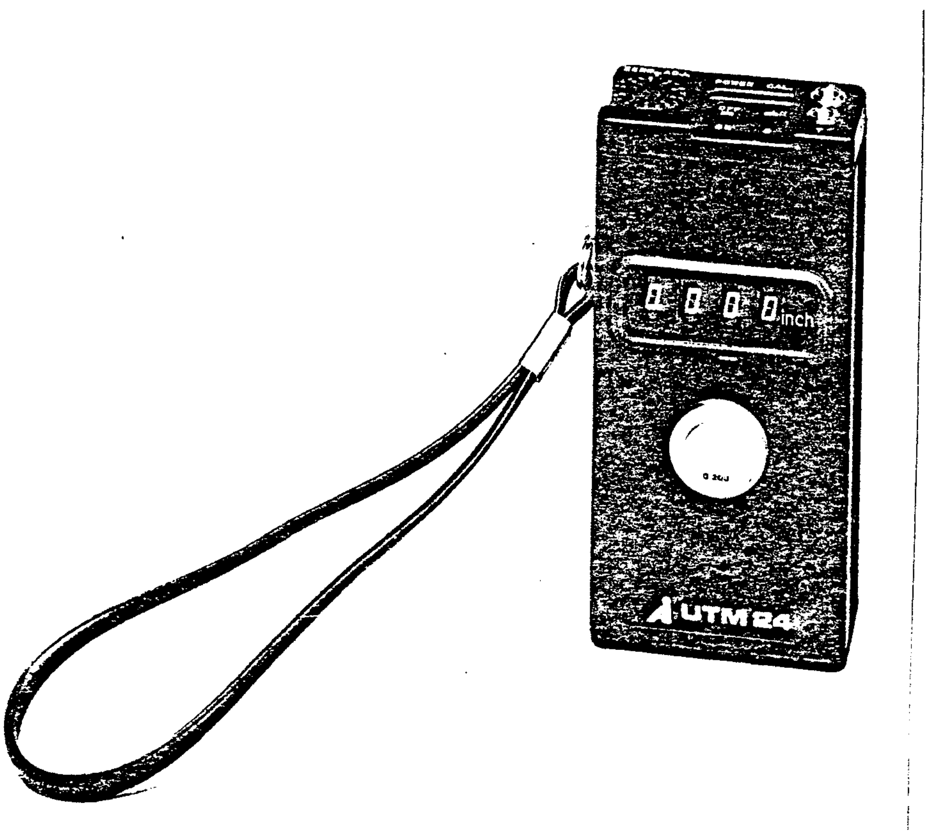


FIGURE 4-6. Model UTM-24 Thickness Tester

Photographs Courtesy of Automation Industries, Inc./
Sperry Products Division

Panametrics, Inc.

Waltham, MA 02154

The Model 5226 Ultrasonic Thickness Gage is available from this organization. It is a lightweight portable unit and can be used on pipes, pressure vessels and storage tanks to determine thinning of the metal due to corrosion and erosion. The specifications of the unit are as follows.

Thickness Measurement Range	0.040 to 10.000 inches or 1.00 to 199.99 mm
Calibrated Accuracy	± 0.004 inches or ± 0.1 mm over measurement range
Resolution	0.001 inches or 0.01 mm or 0.1 mm
Velocity Calibration Range	0.0500 to 0.7999 in/μsec or cm/μsec
Zero Adjustment Range	± 1.3 μsec or ± 0.15 inches (± 3.9 mm in steel)
Display Type	4½ digit high contrast liquid crystal display with switchable backlight and fixed decimal point
Display Mode	Switchable HOLD/BLANK HOLD—Display holds the last reading. Decimal point blinks to indicate hold mode BLANK—Display blanks when no reading is being made
Transducer Type	Dual (pitch-catch) pulse echo
Test Mode	First echo measurement
Gage Operating Temperature Range	0° to 50°C
Transducer Operating Temperature Range	− 40°C to 500°C surface temperature (intermittent use)
Power Requirements	100, 115, or 230 VAC, 50-60 Hz, 5W max. (Charger/AC adaptor) 6VDC, 2.6 Amp-Hr
Battery Type	6V rechargeable solid gel battery
Battery Life	8 hours continuous operation (automatic shutoff extends battery life)
Battery Charging Time	16 hour maximum charging time (fully discharged battery)
Automatic Shutoff	Gage automatically shuts off power approximately 3 minutes after last reading
+ Sync Output	Positive $t_r < 30$ nsec; $Z_{out} = 50\Omega$
Rcvr Monitor Output	± 0-2.4V from 50Ω source, no load
Marker Output	± 4V TTL logic pulse with main bang blank pulse superimposed
Size	2¾" × 6½" × 9 9/16" (70mm × 165mm × 242mm)
Weight	4¼ lbs. including battery (1.9 kg)

This unit complete with transducer, carrying case, and cable presently (5/80) sells for $2195.

NDT International, Inc.

West Chester, PA 19380

Conducts tank thickness testing on a contractual basis. The following page provides typical costs for this type of service. The concern has developed a device that magnetically attaches to the tank and actually crawls over the tank surface to provide thickness data. The "magnetic crawler" is powered by two 12 volt motors which allow the operator to "drive" the unit on the sides of the tank.

A supply of water couplant is fed to the transducer which is gimbel mounted under the mobile device. The design enables the operator to make continuous scans and gage the tank shell thickness from either the top of the tank or from grade level. The following figure (Figure 4-7) provides a view of the instrument while in service while the strip chart (Figure 4-8) illustrates a typical readout showing thinned or corroded sections of a tank's inner shell metal.

The unit which can also be purchased at a cost of $5100 (6/80) has the following basic data.

Required Utilities:	12 volt D.C. Water at 50 PSI
Required Electronics:	Ultrasonic Instrument with time analog gate such as the Nortec 131 D Ultrascope.
Weight:	19 lbs.
Speed:	0 to 10'/min.
Holding Force:	250 lbs.

NDT INTERNATIONAL, INC.
711 CREEK ROAD
WEST CHESTER, PA. 19380
(215) 793-1705

RATE SCHEDULE

1 Man - NDT Level II	$28.00/hr.
2 Men - NDT Level II & Helper	$40.00/hr.
Immersion Inspection	$35.00/hr.
Level III Work	$35.00/hr.
"C" Scan Inspection	$35.00/hr.
Milage	.20/mile
Expenses	Actual
Overtime	1.5 x Rate
Sundays & Holidays	2.0 x Rate
Night Shift Work	+ 15%
Minimum Charge	5 hours

Terms: Net 15 days

EQUIPMENT RENTAL

Ultrascope	$25.00/Day
Digital Hand Scanner or NDT-6D/Recorder	$45.00/Day
Magnetic Crawler	$150.00/Day
Magnetic Tapes	$15.00/ea.

In order to avoid confusion NDT International would like to specify its policy on billing for field work. It is as follows:

Time: All time expended is considered working time be it travel, report preparation, equipment clean-up, etc. and will be billed at normal rates for that time period.

Expenses: Field engineers are entitled to submit expenses as follows:

Meals: 8-10 hours - 1 meal
10-12 hours - 2 meals
Over 12 hours - 3 meals

All additional expenses pertaining to the job such as motel, tolls, parking, car rental, air fare, etc. Receipts will be submitted for all expenses over $5.00

Ultrasonic Transducers and Eddy Current Probes will be billed at cost where unusual wear exists and causes rapid deterioration.

Effective 10/79

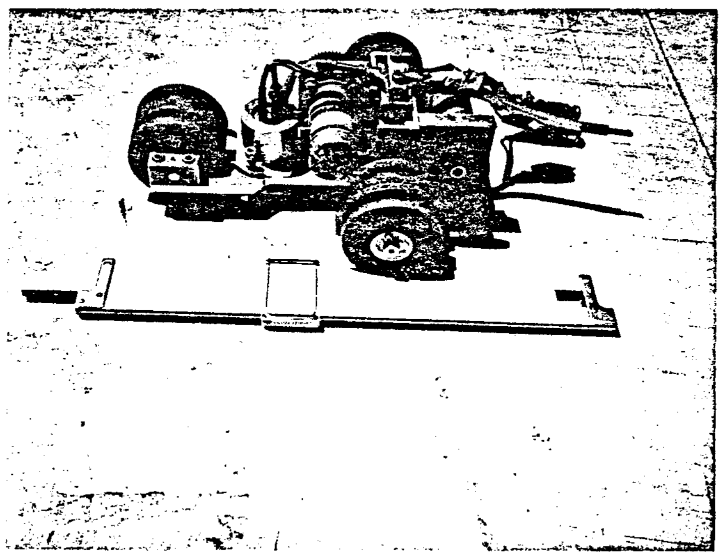


FIGURE 4-7. NDT International, Inc.
Thickness Gage In Active Service

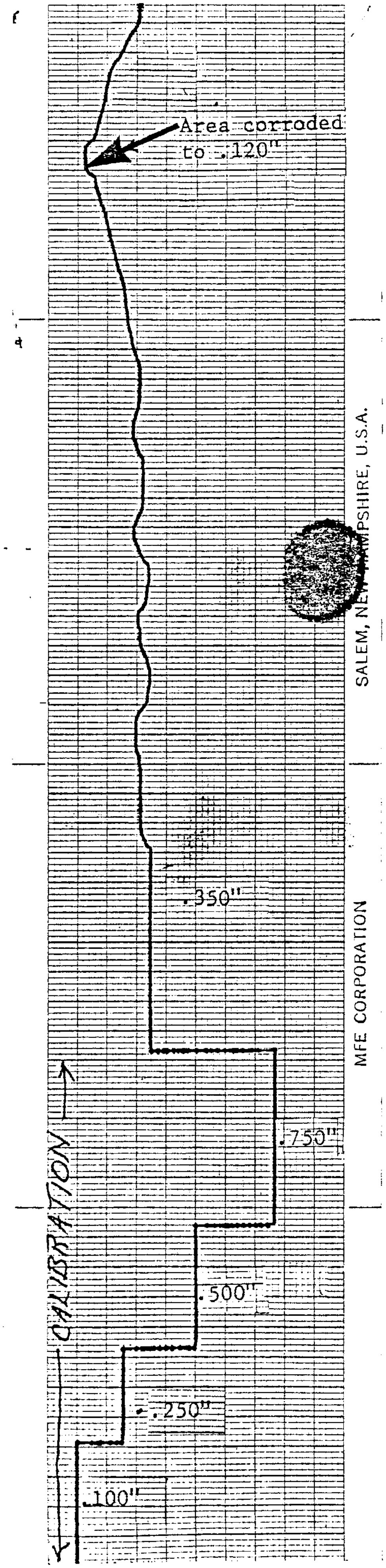


FIGURE 4-8. NDT International, Inc. Typical Strip Chart Readout.

NOTE: "Bathtub Ring" at air liquid interface with .120" of metal corroded away.

4.4 Bulk Storage Tank Vapor Emissions

The release of hydrocarbon vapors into the atmosphere develops a serious fire hazard that could result in the loss of one or more industrial complexes. Naturally, the entire tankage could be, and has been, lost in the ensuing halocaust. The vapors generate an objectionable odor which is very noticeable in the area of refineries and bulk storage facilities. This odor has already distracted from the good neighbor relationship so eagerly sought by the oil industry.

There is also a heavy dollar loss from vapor release which, according to the Chicago Bridge and Iron Company* (CBI), results from the replacement of the crude oil and its products. This involves duplication of all costs from exploration work up to the operation where the loss of the usable liquid occurs. In short, the later the loss occurs as the oil moves from well head to the final consumer, the more costly it is to replace.

Of greater importance is the actual loss of product in a period of short, in fact, dwindling supply.

CBI has calculated that one 80,000 barrel cone roofed tank in a typical operation can be expected to

---

CBI Bulletin 533 "Evaporation Loss Prevention" lose almost 2,700 barrels of gasoline each year from evaporation. Under federal designation this would be considered a major spill in either coastal or inland waters if it occurred at one time rather than over the course of a year. At a current market price of ±$1.30/ gallon the dollar loss per year would be in the vicinity of $147,420 from a single tank. Based on the number of tanks in service nationwide, although the actual figure is not known, the dollar loss must be astronomical.

It must also be accepted that the release of vapors is in fact a spill. In this case a known or intentional rather than accidental discharge. Obviously it behooves industry to effectively control the release of vapors from bulk storage tanks. The intent of this section of the report provides guidance toward this end.

4.4.1 Fixed Roof Tanks

The fixed or cone roof tank is categorized by tank manufacturers as the minimum acceptable standard for the storage of volatile liquids.

CBI reports that the amount of evaporation from a tank depends strongly upon the true vapor pressure of the liquid at the average storage temperature. The average storage

---

*U.S. News and World Report, January 7, 1980 temperature for a particular site is about five degrees Fahrenheit above the mean atmospheric temperature. Figures 4-9 and 4-10 depict average storage temperatures and average daily temperature changes on a mainland national basis. Figure 4-11 provides the true vapor pressure, using the Reid vapor pressure, the slope of distillation curve and the average storage temperature. Figure 4-12 provides the yearly breathing loss from the true vapor pressure, the average tank outage (distance from liquid level to tank top) and the tank diameter. The inset illustration graphically shows the reduction in vapor loss based on the external color of the storage tank. The reduction from painting a tank white develops the first engineering recommendation in this section of the report. Specifically dark colors, or company colors, should be avoided. This alone can reduce vaporized emissions by almost 50 percent.

Presently there is a trend to convert fixed roof tanks into integral floating roof tanks. This is done by installing a pipe column or guide bar from floor to fixed roof. Following this action a membrane sized to suit the tank diameter is installed within the tank. This has been done using pie sections of styrofoam "welded" together with fiber glass and polyester resin binder. The final product floats on the surface of the stored liquid, rising on the central guide/pipe column with the rise and fall

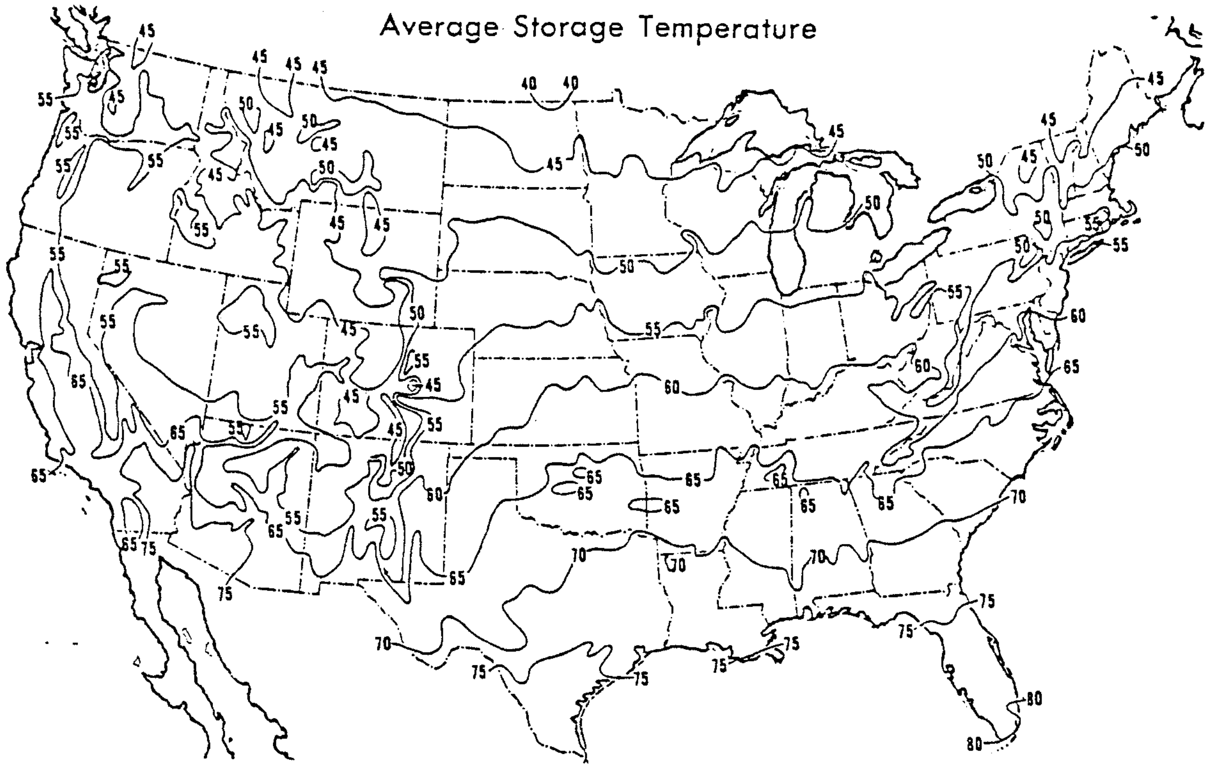


FIGURE 4-9

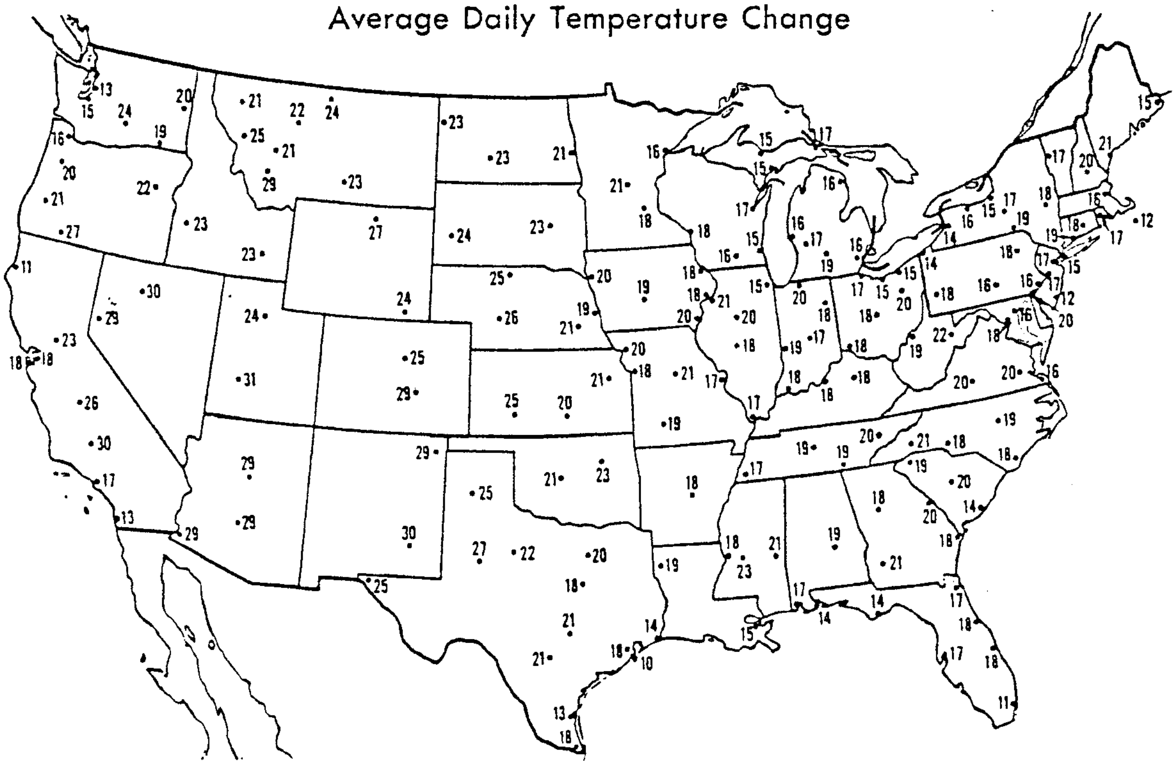
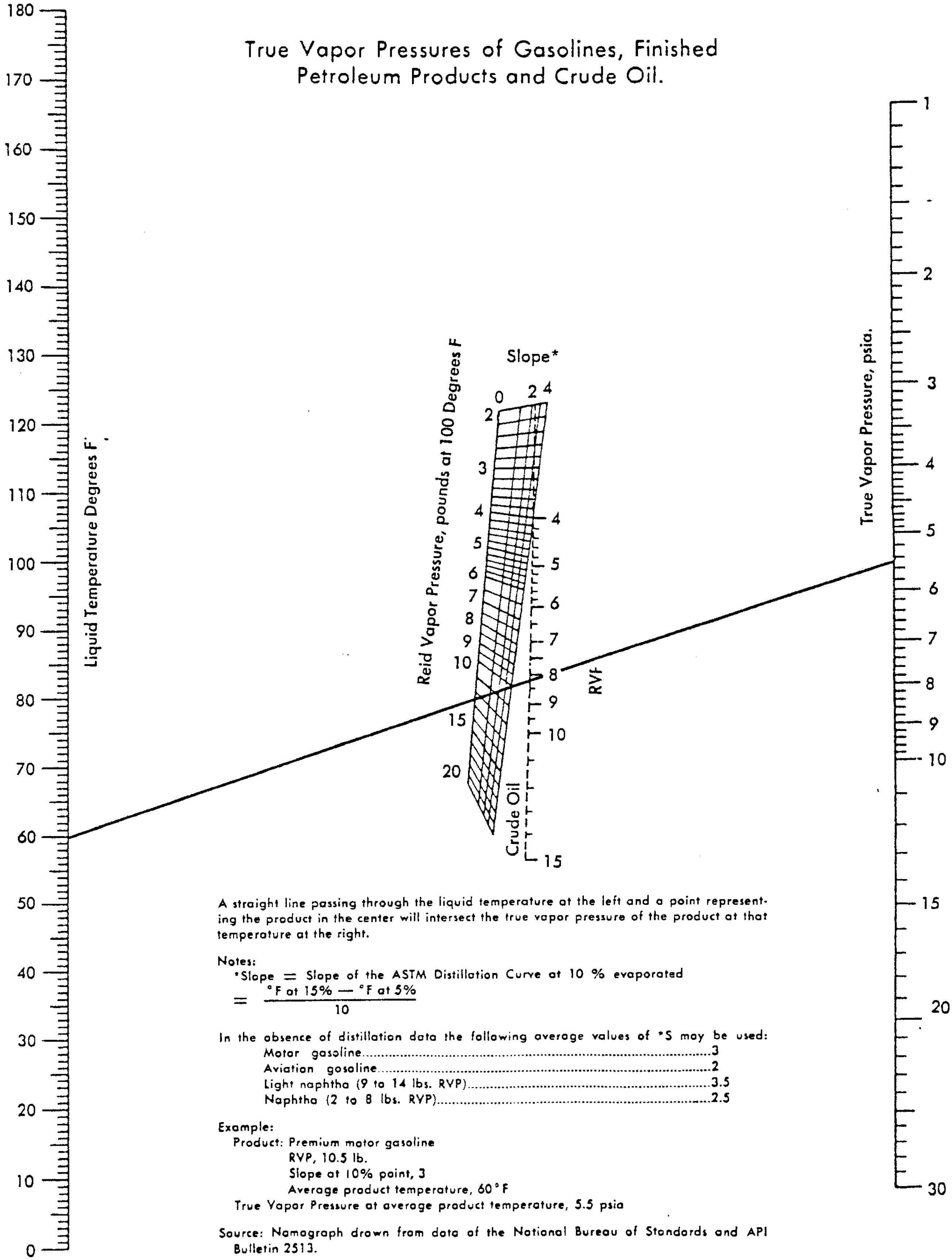


FIGURE 4-10

(Figures: Courtesy of Chicago Bridge & Iron Co. (CBI



A straight line passing through the liquid temperature at the left and a point representing the product in the center will intersect the true vapor pressure of the product at that temperature at the right.

Notes:
*Slope = Slope of the ASTM Distillation Curve at 10 % evaporated

$$= \frac{°F \text{ at } 15\% - °F \text{ at } 5\%}{10}$$

In the absence of distillation data the following average values of *S may be used:

Motor gasoline.......3
Aviation gasoline.......2
Light naphtha (9 to 14 lbs. RVP).......3.5
Naphtha (2 to 8 lbs. RVP).......2.5

Example:
Product: Premium motor gasoline
RVP, 10.5 lb.
Slope at 10% point, 3
Average product temperature, 60°F
True Vapor Pressure at average product temperature, 5.5 psia

Source: Nomograph drawn from data of the National Bureau of Standards and API Bulletin 2513.

FIGURE 4-11
(Figure courtesy CBI)

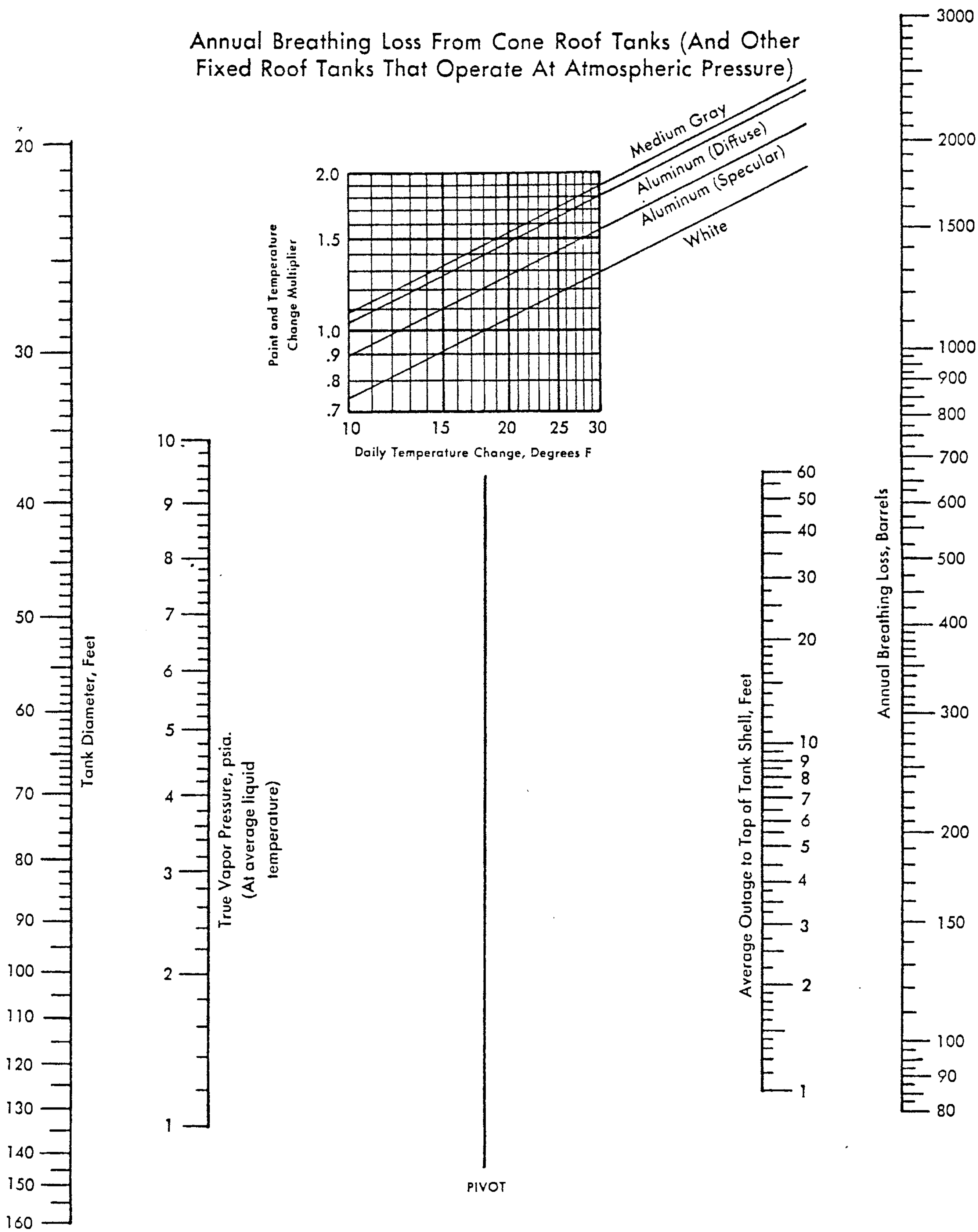


FIGURE 4-12

(Figure - Courtesy of CBI)

of the liquid level. In this manner the available vapor space is reduced and emissions are reduced in proportion. Other floating membranes have been fabricated of sheet aluminum and even suitably braced synthetic sheeting.

CBI as one of the leading organizations in evaporation loss prevention has developed the "Weathermaster" tank (Figure 4-13) which is a fixed roof tank adapted for floating roof service. The "Weathermaster" tank combines the advantages of both the fixed and floating roof tanks. The design keeps the elements -- snow, ice, rain -- out while keeping the product in. These tanks are available in diameters up to 320 feet (97.6 m).

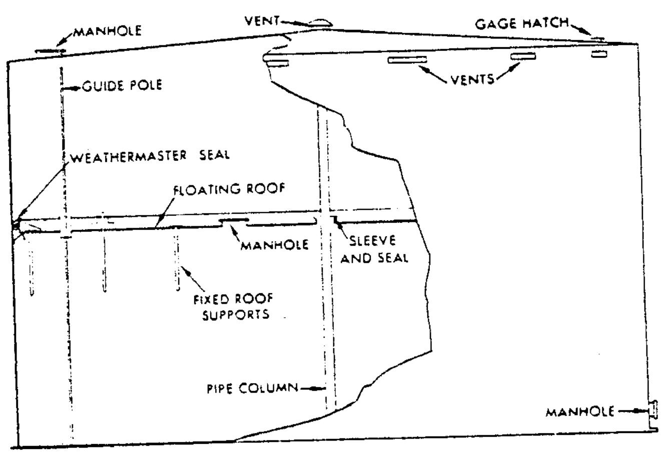


FIGURE 4-13. Weathermaster Floating Roof Tank (CBI illustration)

A fixed roof completely covers the tank while a steel inner single deck floating roof, complete with a resilent foam seal that contacts the inner surface of the inner shell of the tank (Figure 4-14). In addition to a central pipe column or guide, this design incorporates guide poles as depicted in Figure 4-13.

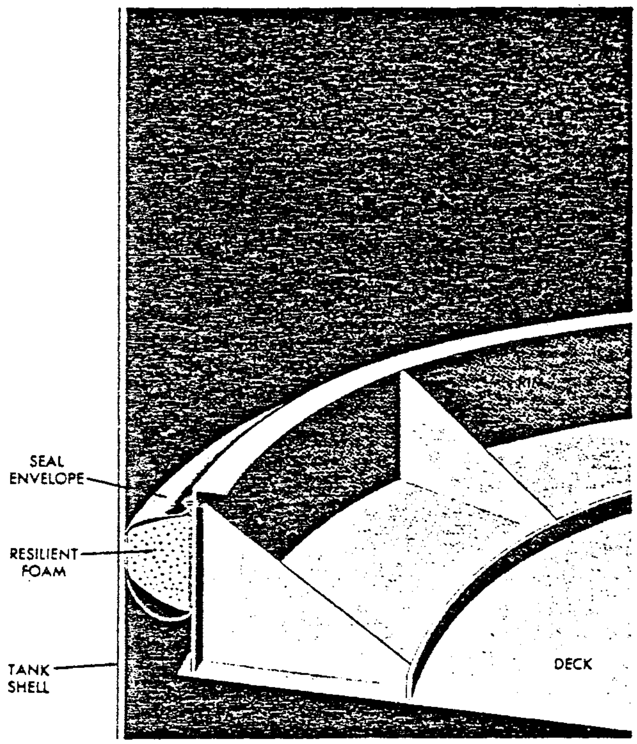


FIGURE 4-14. Horton Resilient Foam Fabric Seal for Floating Roofs in Weathermaster tanks (CBI illustration)

The fixed roof completely covers the tank while the steel inner liner reduces evaporation loss and product emissions by eliminating vapor space. At the same time the internal floating roof effectively combats internal corrosion and product deterioration. The design also eliminates the need for roof drainage systems as associated with conventional floating roof tanks which are described later.

The advantages of these designs are manifold: Maintenance costs normally associated with floating roof tanks are reduced. There is no snow to remove from the floating roofs, no icing on seals, and no drains that require constant attention. Tests (CBI) have also proven that the space between the floating roof and the fixed roof does not contain flammable mixtures except for a short time immediately after product is pumped into an empty, or near empty, tank.

Internal floating roof tanks are suitable for the storage of products usually stored in other floating roof tanks. Precautions should be taken, however, for successful operation during butane blending or mixing procedures and storage of boiling hydrocarbons or gaseous products. Any of these conditions can cause severe agitation of the product beneath the floating roof. This could result in product splashing onto the roof around the seals or roof support sleeves.

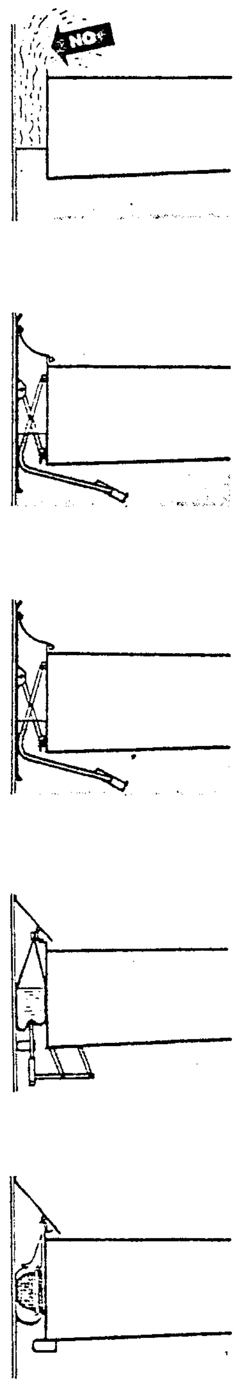
Existing tanks with self-supported or column-supported roofs or ones provided with same can be readily converted to floating roof tanks providing the outer shell is round and vertical columns are available, or can be made available, to guide the rise and fall of the floating roof.

The second recommendation directed toward losses and/or spills from vapor emissions is that losses can be drastically reduced by converting fixed or cone roof tanks to integral floating roof systems. The actual reduction in emissions cannot be readily predicted since this is greatly dependent on knowing the extent of tank use, product throughput, number of fillings per year, and general environmental conditions -- heat, cold, wind, tank color, etc.

4.4.2 Floating Roof Tanks

Until the advent of the integral floating roof tank the standard means of controlling the release of vapor emissions was the floating roof tank. The floating roof completely covers the product and rides up and down on the surface of the liquid thereby eliminating the vapor generation space. Roof buoyancy is maintained by an air-tight annular ring known as a "pontoon" or by using a double deck design whereby air retention space is gained between the upper and lower deck. The air space also provides a degree of insulation from the heat of the sun and inhibits "boiling" of the stored product.

All floating roofs have some type of seal that rides on the inner surface of the tank. There are a variety of designs that control the release of vapors. Figures 4-15 and 4-16 indicate designs used by CBI for their Horton Floating Roof Tank Seals.



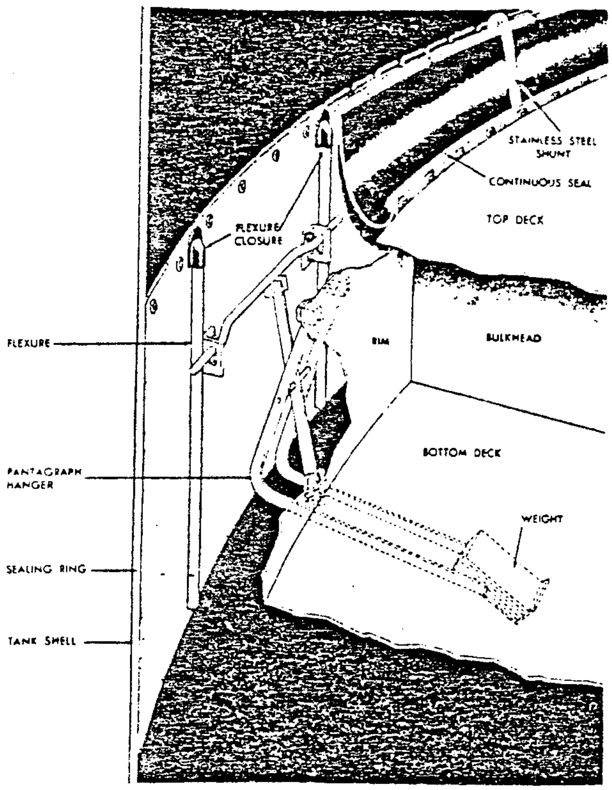
SR-1
FLEXURE SEALING RING

SR-3
SMOOTH SHOE SEALING RING

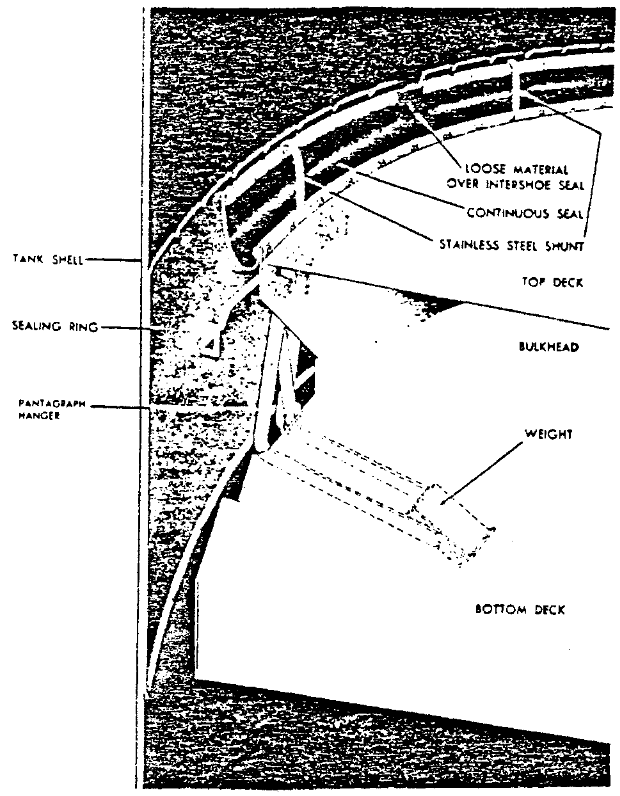
SR-5
LIQUID FILLED FABRIC SEAL

SR-7
RESILIENT FOAM FABRIC SEAL

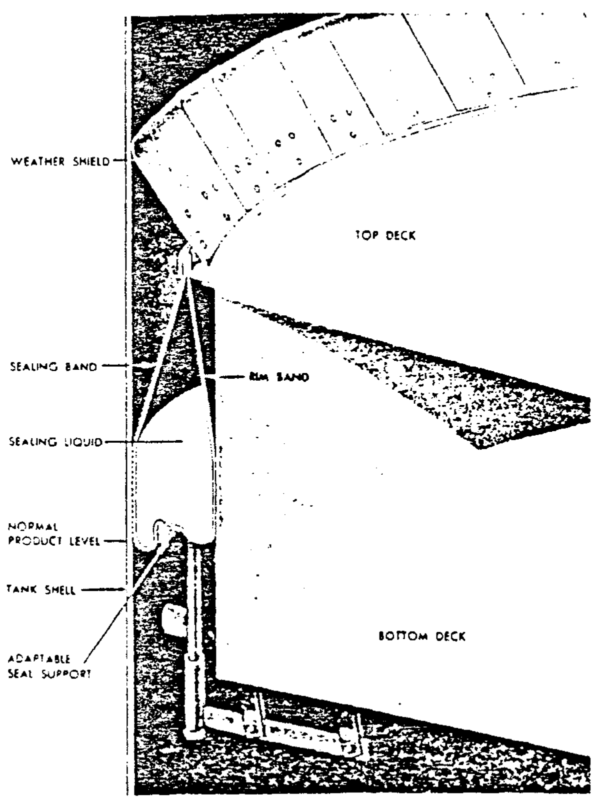
FIGURE 4-15. Floating Roof Seals
(Illustration - Courtesy CBI)



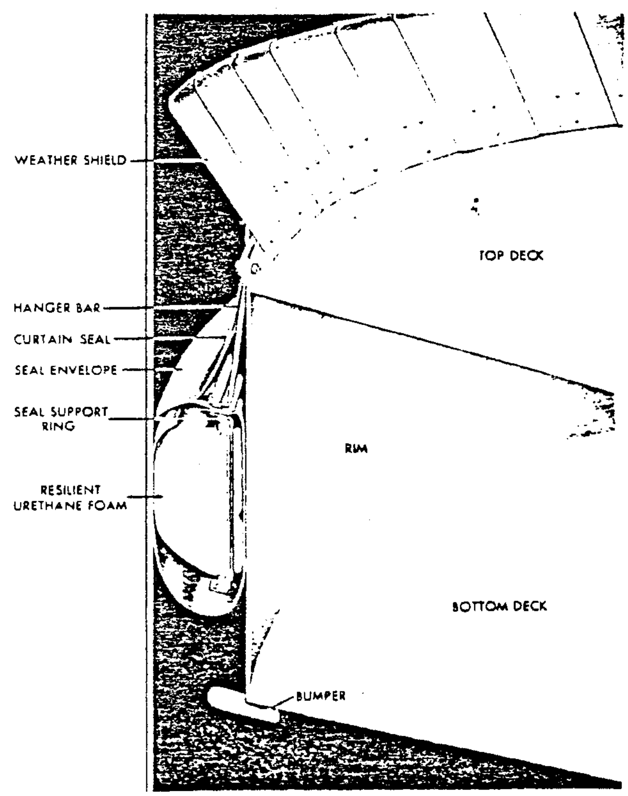
CBI/Horton SR-1 Seal



CBI/Horton SR-3 Seal



CBI/Horton SR-5 Seal



CBI/Horton SR-7 Seal

FIGURE 4-16. Floating Roof Seal Details
(Illustrations - Courtesy CBI)

Some floating roof drains direct the rainwater into the tank from the center of the roof. This naturally results in the accumulation of water in the bottom on the tank and a certain degree of product contamination.

Other drains employ flexible or articulated drain lines that direct the water through the tank shell into the diked containment area.

Returning to drains that enter into storage tank, syphons are designed to prevent the contained product from back flowing up onto the roof of the tank. By this design water contained in the drain and the pan to which it is attached restricts the upward flow of product. The water does, however, drain through the stored product and must be drained off at frequent intervals during heavy rainstorms. This type of drain is prone to freezing in below freezing temperatures and they are limited in use to storage vessels containing products have a specific gravity of 0.85 or less (at least 15 percent differential between the stored product and the rainwater).

Drains are also available with swing or articulated joints that project down into the bottom of the tank. The articulated joints compensate for the rise and fall of the tank's contents and can be connected to a tank water draw valve or can discharge drained water into the bottom of the tank for temporary storage and ultimate water drain valve draining.

Flexible hose drains provided a fourth means of handling accumulated rain water and directing it either into the tank or to a water drain connection. This design incorporates a specially fabricated hydrocarbon-resistant synthetic rubber hose, reinforced with fabric, and protected against kinking and collapse by helically wound reinforcing wire. The hose is also weighted to prevent airlock with a steel cable reinforced lead core rod. These drains can become blocked and drainage can become restricted in freezing weather. Actually should the hose become ice bound in the bottom of the tank it could be physically damaged when the roof floats in an upward direction.

Figure 4-17 graphically depicts the various drainage systems that are available for CBI Horton Floating Roof Tanks.

In lieu of water drainage problems which can result in contaminated product, the possibility of ice blockage and freezing that could interfere with drain operation, the integral floating roof system offers the best advantages of both the fixed and floating roof tanks.

Edwards Engineering Corporation

Pompton Plains, NJ 07444

This organization has developed a wide series of vapor recovery systems for the collection of hydrocarbon and other

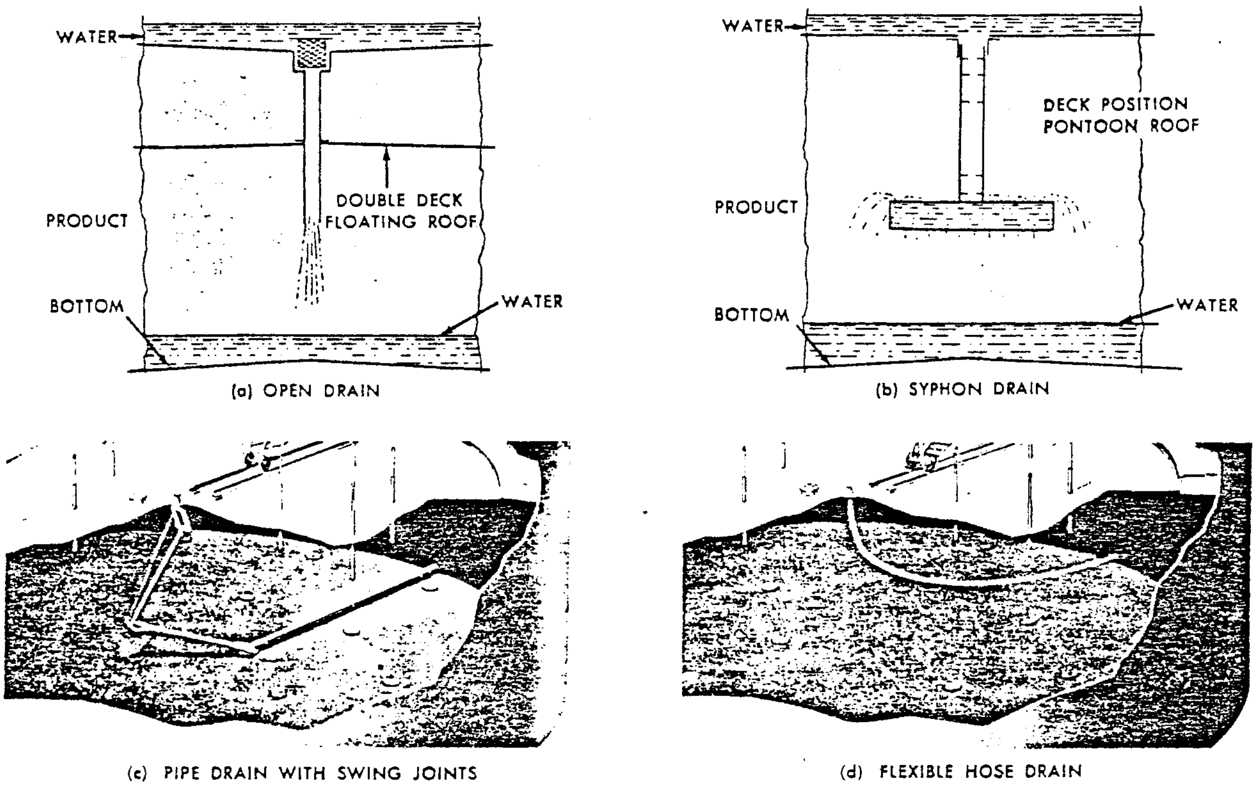


FIGURE 4-17. Rainwater Drainage Systems For Floating Roof Tanks. (Illustration - Courtesy CBI)

condensable gases. The various designs include collection systems for use in the following locations:

- Tank truck loading racks
- Gasoline bulk stations
- Tanker and barge loading facilities
- Chemical process plants

The vapor recovery units, as can be seen in the following photograph (Figure 4-18), are quite compact.

Figure 4-19 and cost and technical data sheets that follow are reproduced in part from the Edwards Engineering Corporation Air Pollution Control Manual to clearly define the various vapor recovery units.

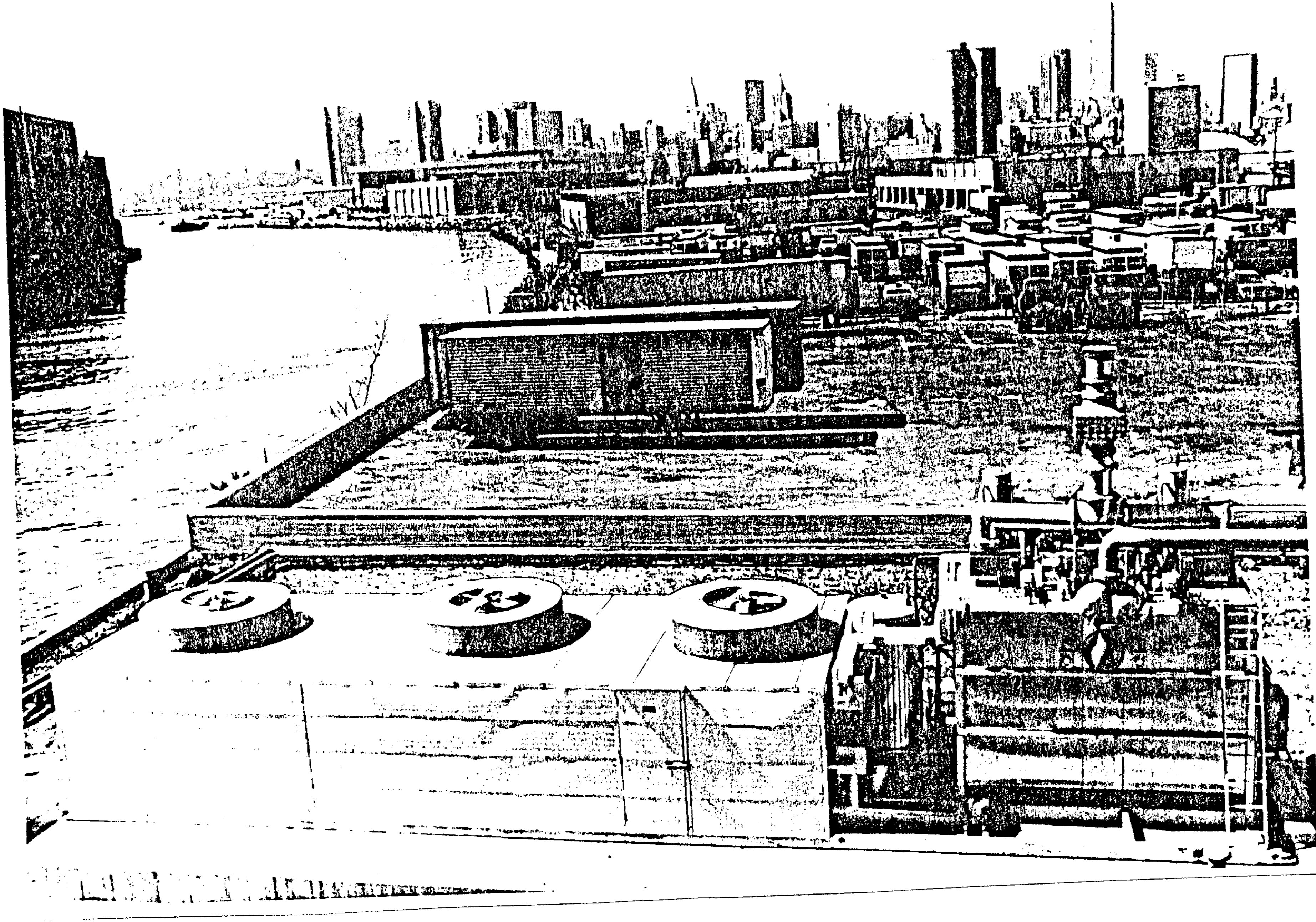
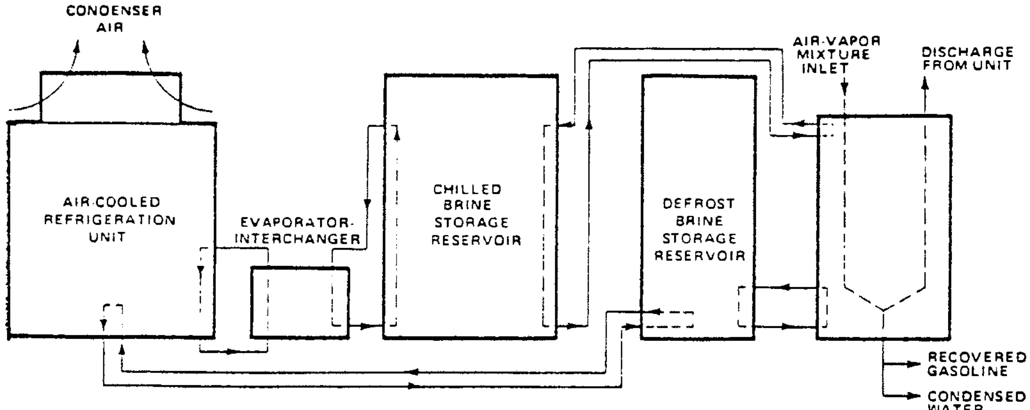


FIGURE 4-18.

Edwards Engineering Corporation
Roof Mounted Vapor Recovery System



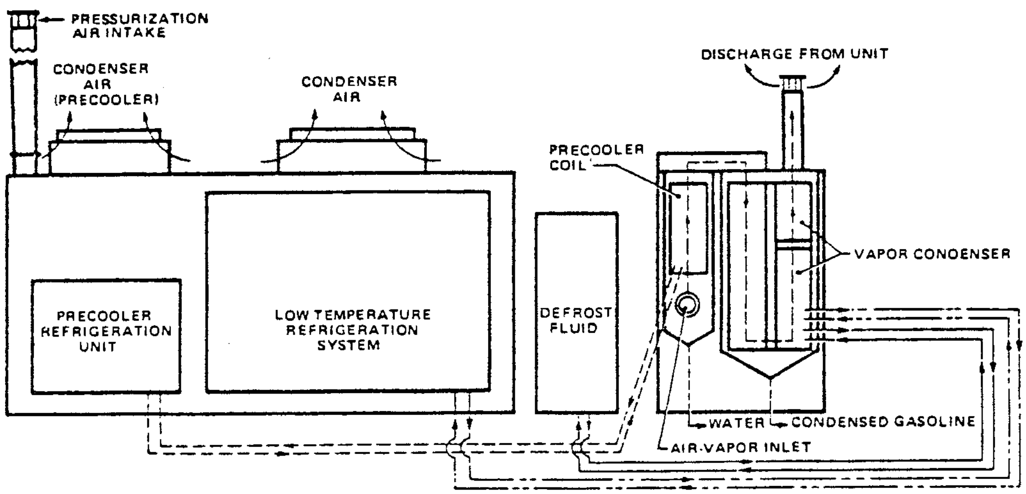
THE VAPOR RECOVERY EQUIPMENT REQUIRED FOR FIXED ROOF INSTALLATIONS DOES NOT REQUIRE A LARGE BRINE STORAGE RESERVOIR. (SEE SPECIFICATIONS)

HOW THE EDWARDS HYDROCARBON VAPOR RECOVERY UNIT WORKS

A cascade refrigeration system follows conventional design, producing temperatures within the evaporator-interchanger in the order of -90°F to -100°F. A cold brine pump circulates methylene chloride brine from the brine storage reservoir thru the evaporator-interchanger to obtain the appropriate low temperature fluid (approx.-90°F) for use in the vapor condenser.

In turn, the low temperature brine coolant is circulated thru the finned tube sections of the vapor condenser. Hydrocarbon vapor and air mixture from the various bulk station filling points is passed over the finned tube sections of the vapor condenser. Entrained moisture in the entering vapor-air mixture condenses and collects as frost on the cold plate fins. Condensed liquid hydrocarbon is collected at the bottom of the vapor condenser.

At periodic intervals, defrosting of the finned surfaces is accomplished by circulation of warm brine stored in a separate reservoir. The temperature of the warm defrost brine is maintained by heat reclamation from the refrigeration equipment. Defrosting is completed in 10 to 30 minutes, depending upon the amount of frost collected on the finned coil.



HOW THE EDWARDS HYDROCARBON VAPOR RECOVERY UNIT WORKS

A conventional Edwards refrigeration chiller provides glycol and water at 34 F for precooling the vapors to remove as much water vapor as possible without the formation of hydrates. The effluent vapors leave the precooler at a standardized water vapor dew-point condition of approximately 34 F and 34 F dry bulb.

The vapors, after leaving the precooler, enter the top section of the condensing column where moisture and hydrates are removed. In the next section, heavier molecular weight ends are condensed in the column. The design and use of a direct expansion refrigeration condenser coil heat exchanger permits raising the refrigeration compressor suction pressure and so increasing the capacity of the unit.

At periodic intervals, defrosting of the finned surfaces is accomplished by circulation of warm brine stored in a separate reservoir. The temperature of the warm defrost brine is maintained by heat reclamation from the refrigeration equipment.

Minimal shut-down time is required to accomplish defrosting in the standard DE-unit, since the unit is equipped with a precooler as previously described. The precooler acts to remove most of the water vapor in the entering hydrocarbon vapor-air mixture, thereby reducing the time required for defrost. Defrosting is completed in 30 to 60 minutes, depending upon the amount of frost collected on the finned coil. Dual condenser units with no time lost for defrost are available.

FIGURE 4-19. Schematic Diagrams of Gasoline Bulk Station Systems

EDWARDS HYDROCARBON VAPOR RECOVERY UNITS: PRICE LIST - Domestic

PRESSURIZED UNITS

	PRESSURIZED MODELS (Note: 1) DE	SINGLE CONDENSER (Requires defrost time of ½-to 2 hours every 24 or 48 hours depending upon conditions).	DUAL CONDENSER (Operates continuously through 24 hours.)
Single Compressor Units (Note 2)	800P	$115,000	(Consult factory for price applicable to unit depending upon extent of operating time and loading.)
	1200P	$131,670	
	1600P	$149,000	
	2400P	$184,680	
	3200P	$218,300	
	4800P	$291,100	
Dual Compressor	6400P	$414,650	
	9600P	$577,100	

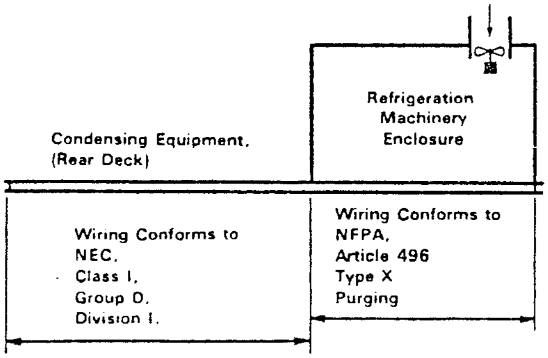
EXPLOSION–PROOF UNITS

	EXPLOSION-PROOF MODELS (Note: 1) DE	SINGLE CONDENSER (Requires defrost time of ½-to 2 hours every 24 or 48 hours depending upon conditions).	DUAL CONDENSER (Operates continuously through 24 hours)
Single Compressor Units (Note 2)	800X	$144,270	(Consult factory for price applicable to unit depending upon extent of operating time and loading.)
	1200X	$173,000	
	1600X	$190,250	
	2400X	$225,350	
	3200X	$260,480	
	4800X	$331,850	
Dual Compressor	6400X	$494,350	
	9600X	$657,780	

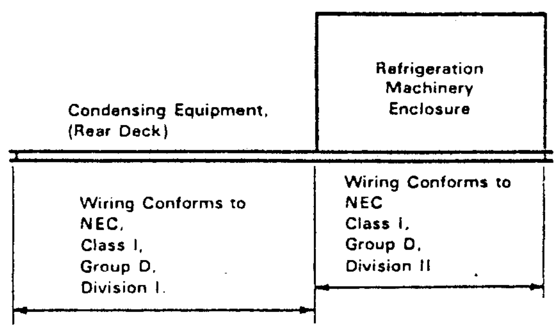
NOTES:

1. *Model numbers apply to DE Series, and to BZ Series by adding suffix DE or BZ to unit model number.*
2. *Models 2400 thru 4800 also available as Dual Compressor Units; consult factory for pricing.*

PRESSURIZED MODELS: provide positive air intake to refrigeration machinery enclosure, and automatic shut-down on positive air failure. Rear deck conforms to explosion-proof requirements.



EXPLOSION-PROOF MODELS: provide for Division II wiring within refrigeration machinery enclosure. Rear deck conforms to explosion-proof requirements.



NOTE: Optional, available thru-out entire unit (consult factory): NEC Class I, Group D, Division I.

NOTE: Prices F.O.B. factory, Pompton Plains, New Jersey

Manufacturer retains the right to change prices, design, and materials without notice.

FORM 8-VRDEP-D-15
Effective Nov. 15, 1979
Replaces 8-VRDEP-D-14

For further information:

Products of
Edwards ENGINEERING CORP.
POMPTON PLAINS, NEW JERSEY 07444
ph. (201) 835-2808 TELEX: 130-131

4.4.3 Additional Vapor Containment Systems

One of the simplest techniques for reducing evaporation loss is to keep storage tanks as full or nearly full as possible. This reduces the vapor generation space, however, supply and demand situations tend to fluctuate and this may not be a practical solution at all times.

Furthermore, evaporation losses from a single, large tank are less than that of several small tanks making up the same total volume or storage capacity. In short, it is preferable to have one large tank than a battery of small tanks containing a specific product.

The CBI organization has developed a series of designs which include Vaporspheres, Vaportanks, Hortondome Roofs and Horton Lifter Roofs to control vapor releases.

The Vaporshere and Vaportanks are actually separate tanks that can be installed in a tank field to collect generated vapors through an interconnected piping system. Once the vapor has condensed it can be pumped back into the main storage tanks on a regular cycle.

Lifter roof and dome designs simply provide additional space to contain the generated vapor on a demand basis. The lifter roof which is mounted on top of the main storage tank is liquid sealed and the actual roof of the tank moves upward and downward with vapor volumn changes. The dome roofed tanks are mounted on top of the storage vessel and a flexible diaphragm within the hemispherical dome moves in accordance with vapor volume changes.

An additional design used to combat vaporization from solar heat evaporation involves a flat roofed tank with the circumferential shell extending up beyond the tank top. A shallow layer of water is then contained within the extended shell to act as a coolant on the tank top.

4.5 Integral Heating Coils

In the colder climates it is a standard practice to heat heavier fuel oils through the medium of steam heating coils. Steam generated from a plant boiler is circulated through the steel or black iron coil to transfer heat to the oil in the lower reaches of the tank. This results in the circulation of the warmed oil to the surface of the tank and the colder upper surface oil travels down toward the heating coil.

A number of problems develop from this heating process, one of which has resulted in major spills. When the heating coils are idle during the summer months the condensate water lies in the coil and corrodes the coil metal from the inside which upon failure (when not under pressure) permits oil to enter the coil. The exhaust from the steam coils on many installations is open to the atmosphere and in some cases to the nearest waterbody. Coil failure has resulted in numerous spills, generally during the nighttime when the spill went unobserved until the dawn daylight.

Some installations return the exhaust steam and condensate back into the boiler water feed system. In installations of this kind oil can enter the waterside of the boiler to act as an insulator and cause burning of the boiler tubes and drums which in turn can result in a metal failure explosion.

There are a number of remedies that can be applied to prevent spills from steam coil failure, the major procedures are as follows:

- Do not leave moisture standing in steam coils when not in use
- Install coils fabricated of Admiralty Metal* in lieu of steel or black iron coils. Although the initial cost will be higher the prolonged life and degree of safety will compensate for the increased purchase cost.
- Do not exhaust condensate from the steam coil to the atmosphere or nearest watercourse. Drain the exhaust to an oil and water separator or to a holding pond.
- Consider the use of external heating coils with outside insulation around the tank

---

*An alloy of not less than 70 percent copper about 1 percent tin with small amounts of other elements and the balance zinc; tin brass. Also known as Admiralty brass and Admiralty bronze.

- Under no circumstances return steam coil condensate back into a boiler water feed system. It is better to loose the condensate than to endanger the plant's steam boiler.

4.6 Liquid Level Monitoring

For many years industry rejected the use of automatic liquid level alarms claiming that they were "unreliable", "difficult to maintain", "worked for a month or so and never worked again", and last but not least "the tank gagers place too much reliance on the device." Rigid environmental laws and the levying of fines for spills that enter navigable waters is gradually changing the situation. Futhermore the technology associated with equipment development and manufacture has advanced considerably over the past decade. There are also many more manufacturers and models to select from, and computorized liquid level gaging has developed accuracies to one half inch with remote direct digital readout at one or more stations.

Examples of a variety of designs follow. It is stressed, however, that the descriptions* as provided do not in any way endorse any particular product.

* When practical descriptions are taken verbatim from the manufacturer's technical literature.

Monitor Manufacturing

Elburn, Illinois 60119

Model CM3A - Material Level Indicator

The CM3A is a highly sensitive measuring device that provides a digital readout on the depth or amount of material contained in a silo, tank, or bin--from 10 to 200 feet in depth. Dependable, easy to use, accurate--it measures contents to within ±1/10th of 1 foot over the total distance to be measured.

The operating principle of the CM3A unit is as simple as it is efficient. Just press a button on a control panel and the unit literally dives into action. A weighted probe, supported by a coated stainless steel cable, is lowered into a storage facility--reaching its "reading" range--quickly. During its downward travel, a counter in the console provides a continuous reading on the amount of material in the bin. When the probe reaches the material level, a slight slack in the cable is automatically sensed in the electrical "head" and triggers the motor to reverse its action--stops the counter, instantly--and returns the probe to its original position. The counter reading remains frozen until another reading is required (or can be manually "erased").

The controlling console can be located in close proximity to the bin, in remote areas away from the bin, or set-up in the production control area with the control devices. A single console is capable of monitoring up to 22 units.

The new CM3A operates efficiently on a variety of materials--chemicals, plastics, cement, coal, paper pulp, vegetable oils, petroleum products and grains. It is not affected by temperature changes, humidity or dusty atmospheres. The CM3A is Factory Mutual approved for use in ordinary locations.

<u>Varec Division Emerson Electric Company</u>

<u>Gardena, CA 90247</u>

Omnitrol Liquid Level Control

The concern manufactures a switch actuator control that can shut off a pump control once a desired (predetermined) liquid level is reached within the storage tank.

The Omnitrol switch actuator operates on a unique and proven principle. The inner magnets are constantly engaged with the outer magnet and pivoting action occurs within the magnetic field at all times.

There are four inner magnets separated by an air space as shown in Figure 4-20. Magnets No. 1 and No. 4 attract the outer magnet. Magnets No. 2 and No. 3 act as a single magnet and repel the outer magnet. All of

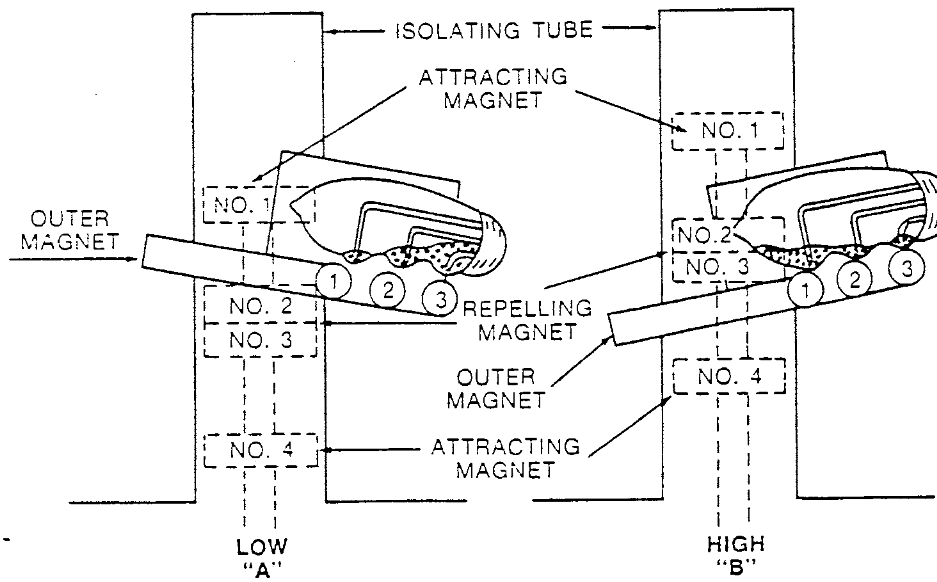


FIGURE 4-20. Principle of "Constantly-Engaged Magnetic Field" (Illustration Courtesy Varec Division, Emerson Electric Company)

these inner magnets, as well as the outer magnet, create a separate field and act in such a manner to lock the outer magnet in the position shown in Detail "A." This prevents nuisance switching created by liquid level surges or surface agitation.

As the liquid level rises, the inner magnet stem assembly rises and magnets No. 2 and 3 will be forced through the field of the outer magnet. The repelling force on the outer magnet will then be acting in a downward direction. Simultaneaously, the attracting force of magnet No. 1 will decrease and that of No. 4 will increase. The outer magnet or actuator switch assembly will snap into its new locked position as shown in Detail "B."

Due to the forces encountered, there is no possibility of the outer magnet finding a null point anywhere between the two locked positions; therefore, a complete and positive snap switching action is assured.

High position, liquid level falling. Detail "B" shows the switch and magnet status for high liquid level. As the level falls, all forces described above are reversed until the inner repelling magnets have been forced through the magnetic field of the outer magnet and the actuator is again in the "locked" position shown in Detail "A."

No springs, bellows, diaphragms, or other mechanical devices are required. The only movement of the actuator is the slight tilting of hardened stainless steel shaft in a jeweled pivot bearing.

Automation Products, Inc.

Houston, TX 77008

Dynatrol - Level Detector

When used in conjunction with a relay switch receiver the Dynatrol unit detects the liquid (or slurry) level and provides an "on-off" switch action. The control is described as a dynamic type level switch for application to either high or low point level detection of liquids and slurries. The design entails a puddle (Figure 4-21) driven into vibration by a driver coil. A second coil located in the pick up end produces a voltage proportional to the paddle vibrational amplitude. When the paddle comes into contact with the rising liquid its amplitude of vibration decreases and the output voltage drops to a very low value. The change in output signal operates the contacts of the Relay Switch Receiver (Figure 4-21).

The Model EC-102B Relay Switch Receiver is a transistorized relay package designed for use with the Dynatrol Detector when "on-off" switch action is desired. The contacts of the EC-102B are electrically isolated, thereby making possible the operation of any "on-off" device within the ratings of the contacts. If higher ratings are required, an auxiliary relay must be employed. Though it is designed for direct coupling to the detector, it can be installed remotely.

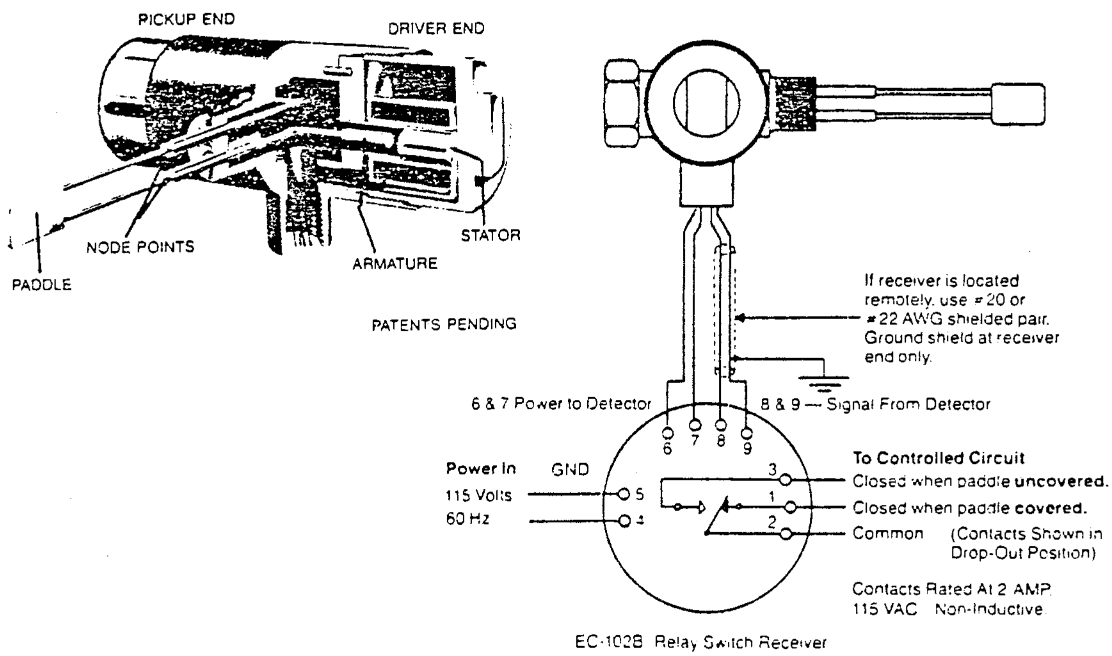


FIGURE 4-21. Dynatrol CL-IORH Level Detector and EC-102B Relay Switch Receiver (Illustration Courtesy Automation Products, Inc.

In addition to acting as a pump shut off control, the relay switch could be readily wired to actuate a visible/audible alarm signal. The complete package, ready for installation sells for $384.00 with a supply time of one week.

<u>Transdata Corporation</u>

<u>Freeport, NY 11520</u>

Liquid Level Instrumentation

The organization manufactures a wide range of liquid level detection and control equipment, some of which are designed for on site level reading while others have a remote readout capability. The following figures and descriptions are directly quoted from the manufacturer. (Figures 4-22, 4-23, 4-24, and 4-25.)

<u>GPE Controls</u>

<u>Morton Grove, IL 60053</u>

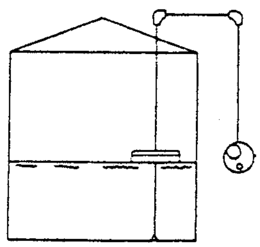
Telepulse Systems

The Telepulse systems can be described as follows:

Telepulse 300

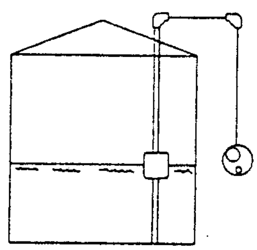
This is a simple and accurate system for remote supervision of storage tank liquid levels and temperatures. It is used mainly for inventory control, <u>prevention of overfilling</u>, and loss of pump suction during discharging. The Telepulse 300 is applicable where there are only a small number of tanks (from 1 to 20) reporting to a central supervisory station. Typical installations include storage facilities at marine terminals, power plants, steel mills, synthetic rubber plants, pulp paper mills, petroleum

Fig. I MODEL 42,000 - AUTOMATIC TANK GAGE



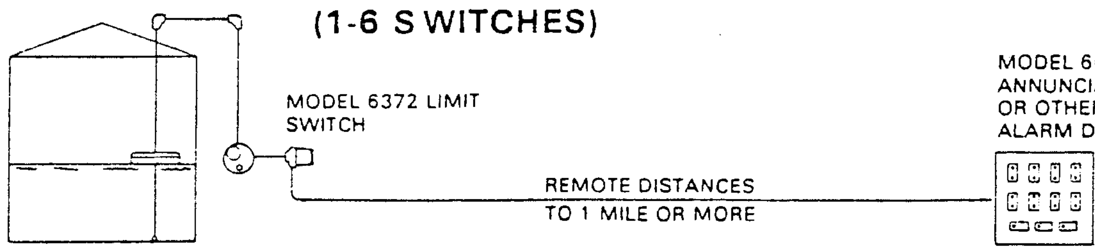
The Protectoseal Model 42000A Automatic Tank Gauge is a float operated liquid level gauge suitable for use on tanks up to 65 ft. high. It provides digital readings in 1/16th inch increments. The gauge head readout can be located at eye level at the bottom of the tank, at the top of the tank, on the outside of a steel firewall or at any convenient location immediately adjacent to the tank. The standard unit is supplied for working pressures up to 15 PSIG. The standard construction consists of aluminum housings with stainless steel trim and a stainless steel float with stainless steel guide wires. The readout can be supplied in the metric system or in tenth of inches or in hundredths of feet.
For pressures beyond the 15 PSIG range, or for corrosive or toxic services, see the Transdata Model 5683 Magna-Float Automatic Tank Gauge.

Fig. II MODEL 5683 - MAGNA-FLOAT LEVEL GAGE



The Transdata Model 5683 Magna-Float Automatic Tank Gauge utilizes the same external components as the Protectoseal 42000A Automatic Tank Gauge except that a non-magnetic floatwell that is sealed at the bottom end extends from the top to the bottom of the tank in order to isolate the automatic tank gauge operating mechanism from the tank contents. The float is center guided by the floatwell and is magnetically coupled to the tape through the wall of the floatwell.
The Model 5683 Magna-Float Automatic Tank Gauge is suitable for use on tanks handling corrosive chemicals, toxic products or liquids being stored at elevated pressures up to 300 PSIG. All of the Transdata accessory equipment that can normally be used with the Protectoseal 42000A Automatic Tank Gauge can also be used with the Transdata Magna-Float Automatic Tank Gauge.

Fig. III MODEL 42,000-AUTOMATIC TANK GAGE WITH MODEL 6372-ADJUSTABLE LIMIT SWITCH (1-6 SWITCHES)

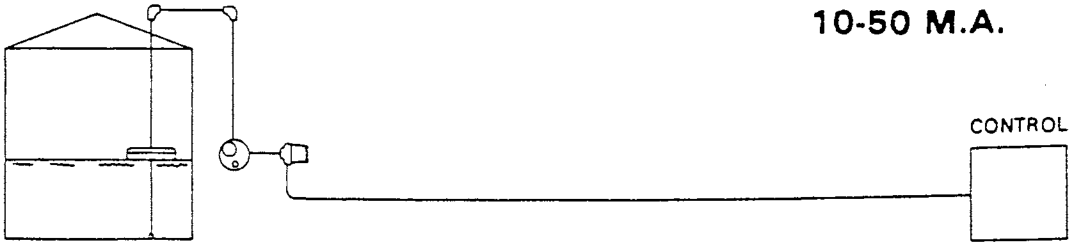


The Transdata Model 6372 Adjustable Limit Switch Assembly can be installed on the gauge head. Up to six adjustable limit switches can be supplied in the explosion proof housing. The standard switches are SPDT, although DPDT are optionally available. They are cam operated and are independently adjustable so that alarm or control circuits can be operated or closed as required at various pre-selected liquid levels. The switches can be used to operate the Transdata 6699 Annunciator/Control System.

FIGURE 4-22. Liquid Level Instrumentation For Indication and Contol

Fig. IV

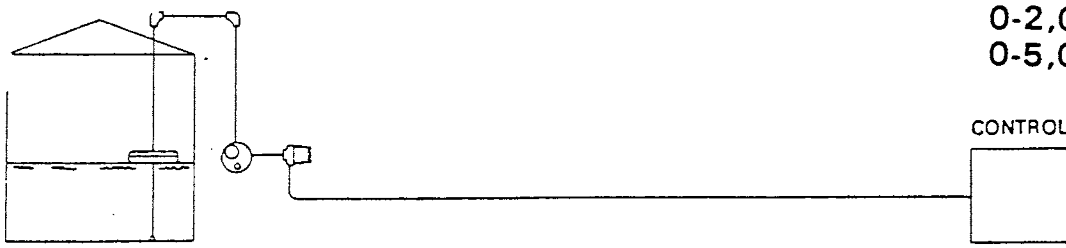
MODEL 5212 MILLIAMP TRANSMITTER
RANGES 4-20 M.A.
10-50 M.A.



The Transdata Model 5212 Milliamp Transmitter can be supplied for mounting on the 42000A Automatic Tank Gauge to provide a milliamp output as a function of liquid level. The two standard ranges are 4-20 milliamps and 10-50 milliamps.
Adjustable Limit Switches can be included within the explosion proof housing for alarm or control purposes, in addition to the analog milliamp output signal.

Fig. V

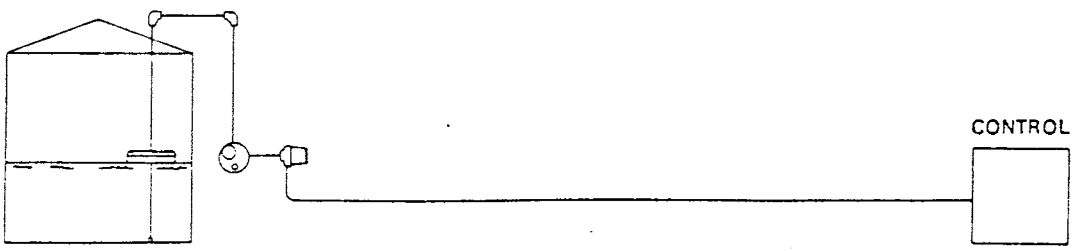
MODEL 5505 POTENTIOMETER TRANSMITTER
RANGES 0-1,000 Ω
0-2,000 Ω
0-5,000 Ω



The Transdata Model 5505 Potentiometer Transmitter is supplied in an explosion proof housing for mounting on the 42000A Automatic Tank Gauge. This provides a variable resistance as a function of liquid level. Numerous resistance ranges are available, such as 0-1000 ohms, 0-2000 ohms, 0-5000 ohms or other ranges to satisfy a customers specific needs. The Transdata Model 5505 Potentiometer is also available with adjustable limit switches for alarm and control purposes.

Fig. VI

MODEL 5877 PNEUMATIC TRANSMITTER
3-15 P.S.I.G. SIGNAL

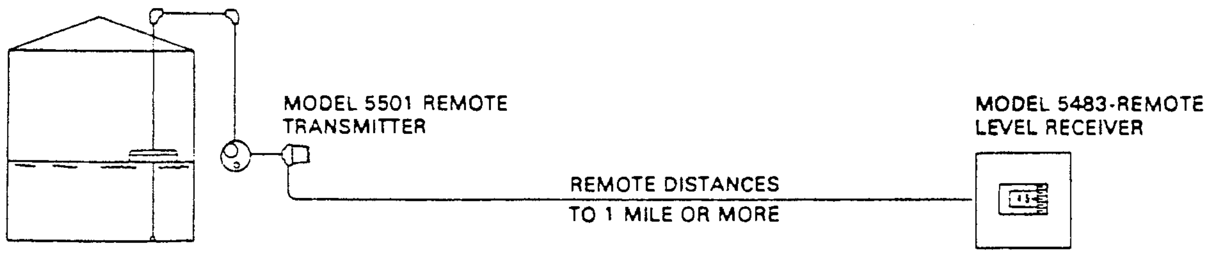


The Transdata Model 5877 Pneumatic Transmitter is designed for mounting on the 42000A Automatic Tank Gauge and is for use in connection with pneumatic instrumentation where a standard pneumatic signal of 3 to 15 PSIG can be used for control or indication. The 3 to 15 PSIG air signal is a function of liquid level but if this proportional analog signal is not desired, the unit can be supplied for on/off control.

FIGURE 4-23.

Liquid Level Instrumentation For Indication and Control

Fig. VII MODEL 5501/5483 REMOTE READING SYSTEM



The Transdata Model 5501 Explosion Proof Remote Level Transmitter is designed for mounting on an Automatic Tank Gauge in order to transmit the liquid level readout to a remote location that can be anywhere from a hundred feet to a mile or more away. The Model 5483 Remote Receiver presents the remote reading in a digital display in feet, inches and sixteenths of inches.
The following descriptions illustrate the standard modifications that are available with this basic remote reading system. These options include adjustable limit switches installed in the transmitter for alarm or control purposes.
The Model 5483 Receiver can provide additional output signals in addition to the standard digital display. These output signals consist of adjustable switches, variable resistance, or standard milliamp output signals.

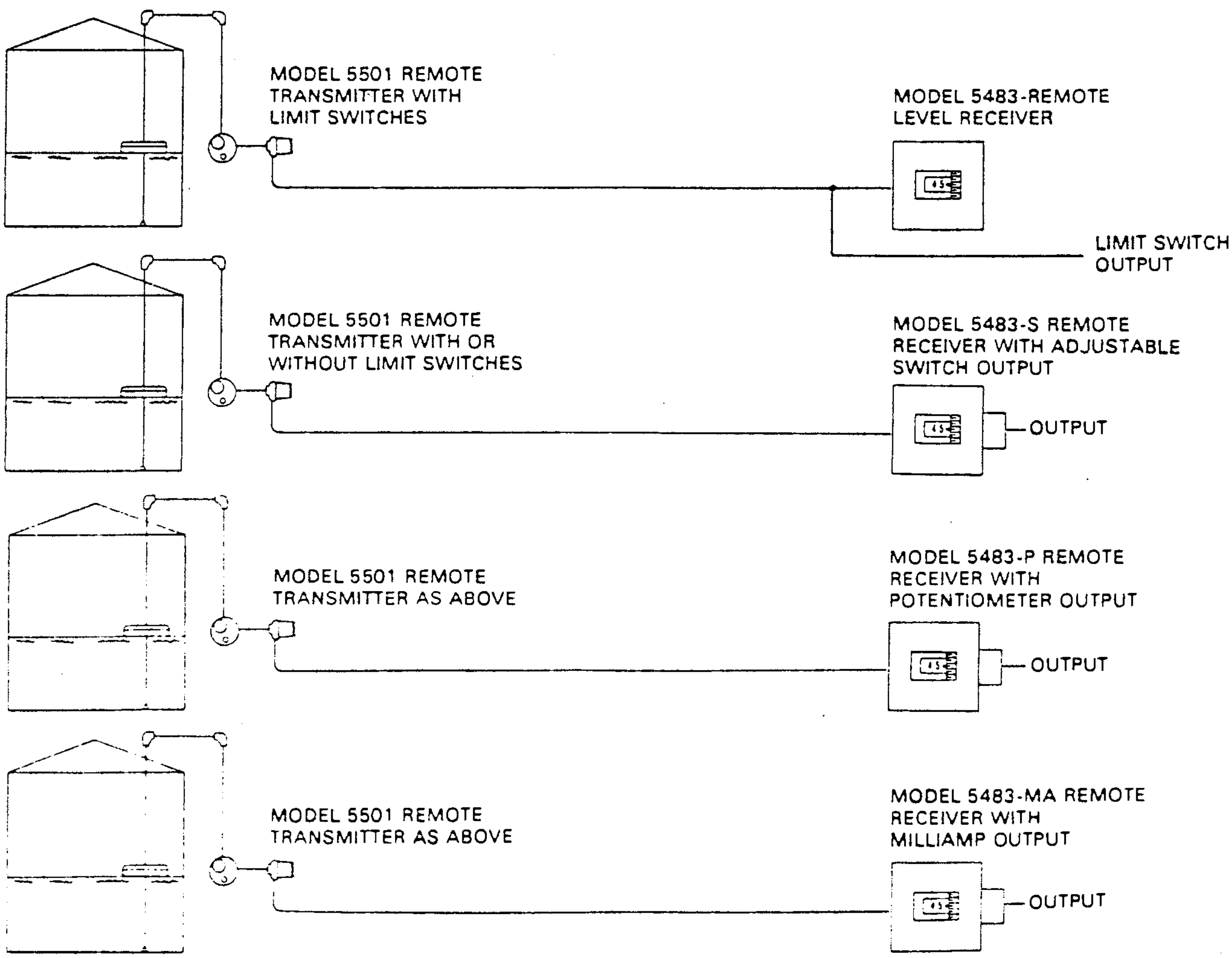
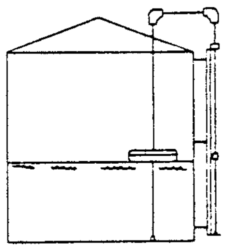


FIGURE 4-24.

Fig. VIII

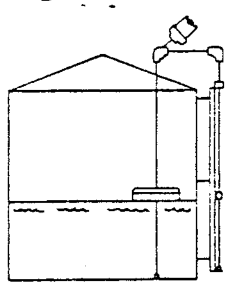
MODEL 40,000, 41,000 - LIQUID LEVEL INDICATORS



The Protectoseal Model 40000 and the Fig. 41000 Liquid Level Indicators are designed for application to process or storage tanks where a readout to within 1" of liquid level is satisfactory and provides the additional convenience of being able to be read out at 100 or 200 ft. away from the tank rather than having to approach the gauge head readout device within a few feet. As is the case with the 42000A Automatic Tank Gauge, the float, guide wires and other critical items are of type 316 stainless steel construction. The board on the side of the tank is of heavy gauge aluminum channel construction and is normally calibrated in feet and inches but can be calibrated in the metric system, decimal system or special calibrations as may be required for the application.

Fig. IX

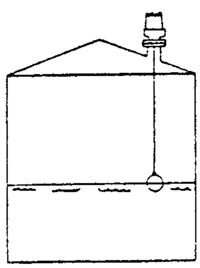
MODEL 6600 - 90° SPOCKET ASSEMBLY



The full range of Transdata accessory equipment that is described for use with the Model 42000A Automatic Tank Gauge can be used in conjunction with the 40000 or 41000 Liquid Level Indicators. This is accomplished by substituting the Model 6600-90 Degree Sprocket Assembly in place of one of the 90 degree pulley assemblies at the top of the tank. The standard cable that is used between the float and the gauge board marker (target) is substituted with a stainless steel bead chain which drives the bead chain sprocket and, in turn, operates the transmitters or switches.

Fig. X

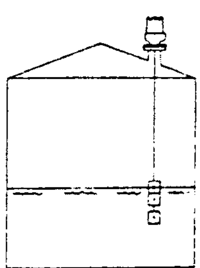
MODEL 6648 - TOP MOUNTED FLOAT SWITCH



The Model 6648 Float Switch is supplied with a 4"-125# flanged connection for mounting at the top of a tank. As the liquid level rises, the float moves a steel armature into the field of a magnetically operated mercury tilt switch that can be used to either open or close a circuit.

Fig. XI

MODEL 6761 - TOP MOUNTED DISPLACER SWITCH



The Model 6761 Displacer Switch is supplied with a 4"-125# flanged connection for mounting at the top of a tank. As the liquid level rises around the displacers a steel armature moves into the field of a magnetically operated tilt switch, which can be used to open or close a circuit. Since the displacers do not float, two points of switch actuation are possible with one switch assembly. The Model 6761 is easily adjusted in the field for level actuation points. These units are especially suited for wide level differential applications, or for surging or agitated liquids.

FIGURE 4-25.

Liquid Level Instrumentation for Indication and Control product terminals and chemical processing facilities.

Telepluse 300 displays accurate tank level readings of tanks up to 120 feet high--accuracy is within $\pm$.25% of the level measuring range. Temperature readings are accurate to within $\pm 1^{\circ}$F or C. High and low liquid level alarms can be incorporated in the system. Liquid levels are read in both metric and English measure. A switch on a display console converts the level display from meters to feet and vice versa.

For single tank installations, the liquid level is displayed constantly on a digital display meter. In multiple tank systems the desired tank is selected by pushbutton on a central console receiver. The console can be free standing on a desk, table, or counter, rack mounted, or built into a custom-designed display.

Telepulse 400

The Telepulse 400 Series are completely integrated systems, providing central supervision of tank levels and temperature gaging in very fine increments. Up to 200 storage tanks can be remotely supervised, gathering liquid level data within an accuracy of plus or minus 2 millimeters or .01 ft. Depending on the number of tanks being monitored, Series 400 systems can update tank level readings from four second to ten per second. Additional equipment options are available which makes it possible to tie in with a computer or provide high-low alarm signals. The data can also be displayed at more than one location through the use of satellite units. An additional desirable feature is the ability of the Series 400 Telepulse systems to "grow" with an installation. By using a modular concept, they readily adapt to the changing requirements of an expanding facility.

The cost of the Telepulse actually demands a complete engineering evaluation and cost estimate. The manufacturer could, however, provide cost data on the components of a Telepulse 300:

Level gage	$500.00	(av. 50 ft. tank)
Transmitter with high-low alarm	664.00	
Telepulse receiver	300.00	(up to 300 ft. distance)
Installation kit	100.00	
Instrinsically safe barrier and power supply	660.00	

The manufacturer estimates that the installation costs would equal the part acquisition cost ±$2224. Figure 4-26 graphically displays the receiver for Model TP 400.

Obviously there are numerous manufacturers and designs of fixed tank level gages available on the market. One additional unit is described largely because it is portable and of quite unique design.

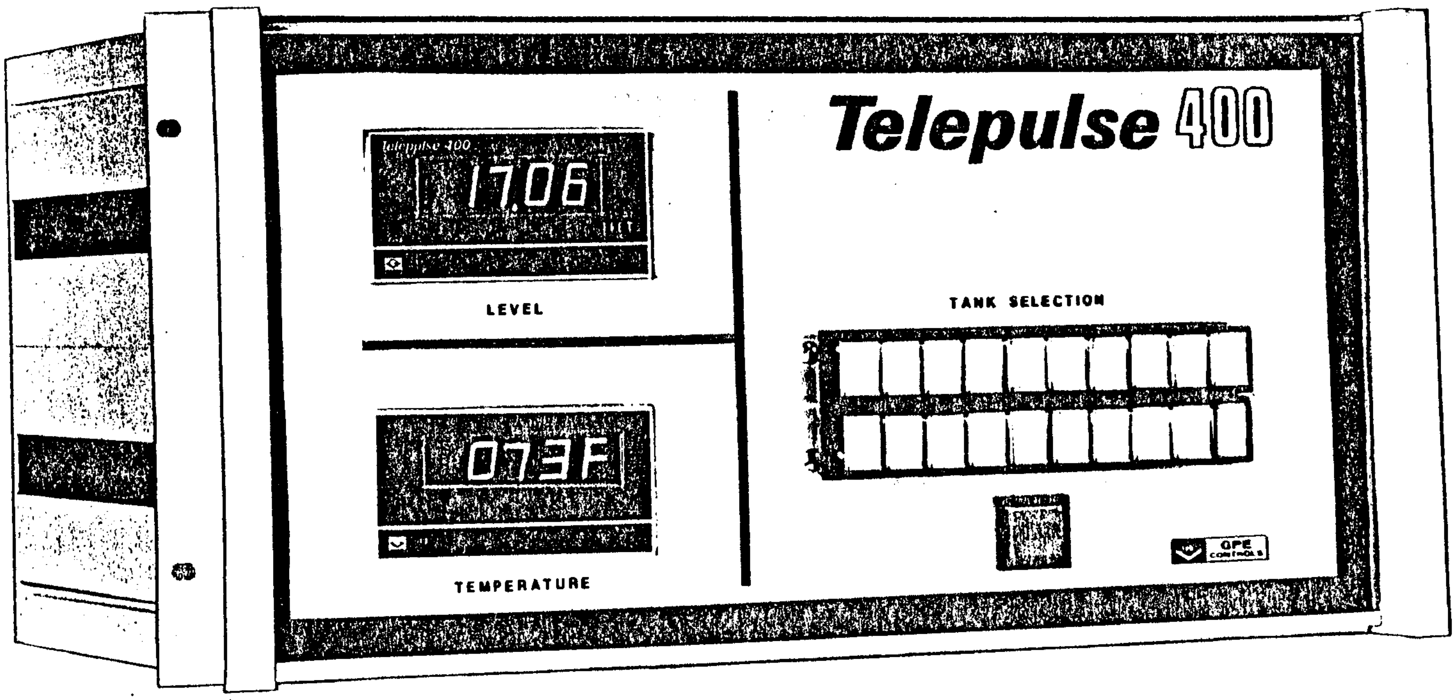


FIGURE 4-26. Telepulse Liquid Level Monitor

Note degree of level accuracy and availability of multiple tank soundings.

(Photograph Courtesy GPE Controls)

Metritape, Inc.

Concord, MA 01742

Metritape Digilert Level Systems

This unit can be characterized as a portable fill alarm that can be used while liquid cargoes are being transferred from a storage container into a transportation vehicle. Its use would include marine tankers, barges, tank cars and tank trucks. It can, however, also be used when fixed storage tanks are being used. The specifications of the unit are as follows:

METRALERT Portable Fill Alarm, Model PFA-80

Dimensions, Overall	Approximately 13"x12"x6"
Total Weight	11 pounds
Cable Length	12 ft, standard
Instrument Temperature Range	-20F to +140F
Sensor Temperature Range	-20F to 190F, standard
Sound Output	Rapid-sweep siren, 1500 to 2500 Hz.
Sound Intensity	110 db, max. at 4 ft.
Electrical Safety Rating	Intrinsically-safe, Class 1 Groups C and D
Battery Life (alarm sounding)	Approx. 2 hours
Battery Shelf Life (between charges)	3 to 4 months
Battery Rechargings	Over 100
Exposed Materials	Epoxy fiberglass, phenolic, Teflon, and neopene, standard

The prinicple of operation is simple. A pressure sensitive head is first lowered into the tank or cargo compartment to the height of the desired liquid level. The pendant sensor is then activated when the hydrostatic pressure of the liquid cargo activates the internal element of the sensor circuit. The manufacturer designates that a number of parallel contacts are provided to give high switching reliability and that the element has been subjected to 100,000 operating cycles without contact failure or evidence of wear or fatigue. Once activated by hydrostatic pressure, the Teflon coated sensor actuates a high intensity horn which produces a high intensity electronic siren sound sweeping from 1500 to 2500 Hz. The sound level reaches 110 db at close range, as loud as can be heard without discomfort.

The concern also manufactures the Digilert level/temperature readout unit which has a built-in audible fill alarm. The system is battery-powered and provides comprehensive tank readings and alarm functions to the deck of a marine transportation vessel, at railroad tank car loading racks, tank truck loading stations or land based storage tanks. The packaging is such that it can be fixed mounted or used in a portable mode at any loading station. Figure 4-27 illustrates the compactness and design of the unit which can be obtained in a variety of models for specific uses.

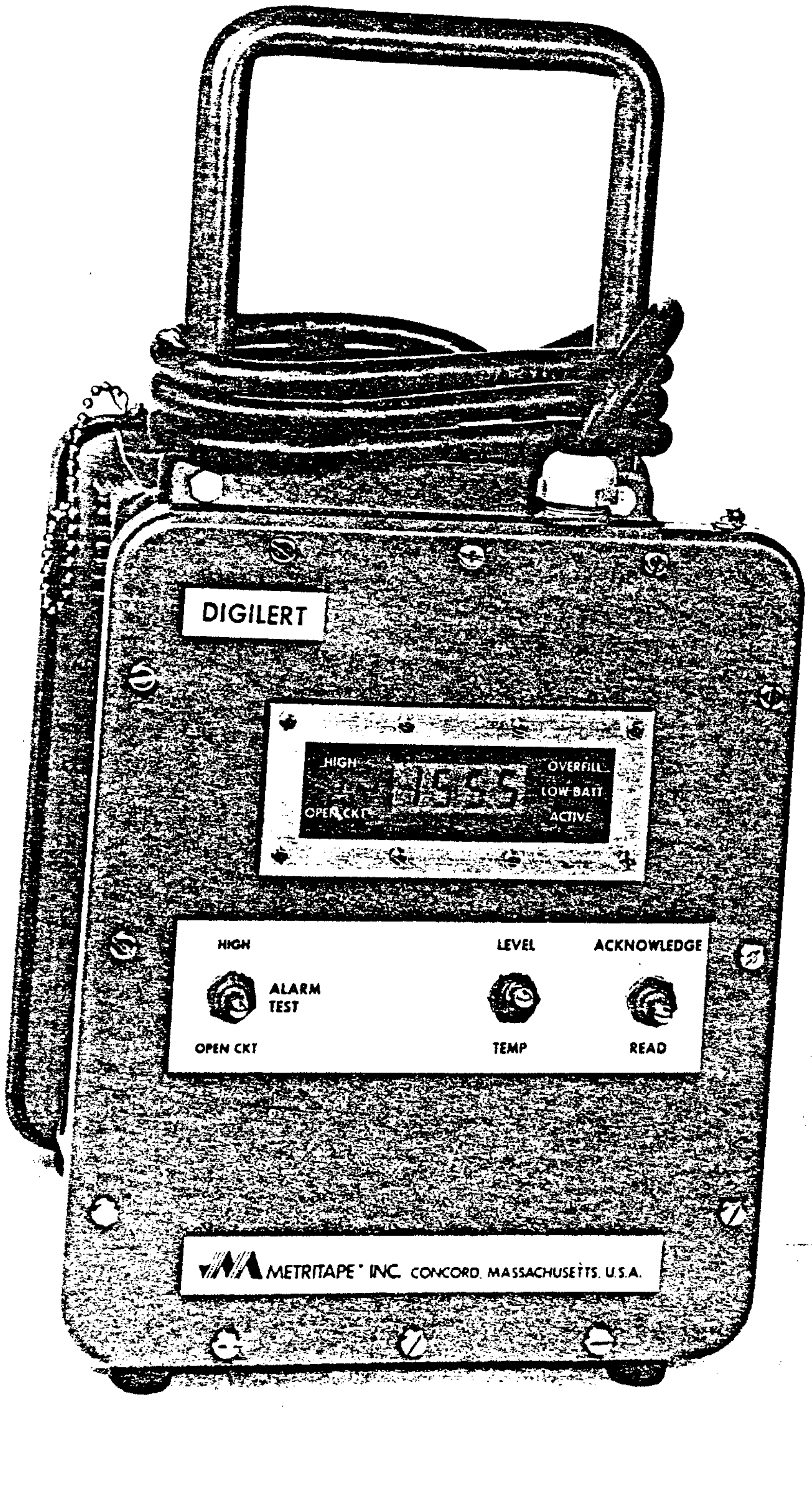


FIGURE 4-27. Digilert Level/Temperature Readout Unit
(Photograph Courtesy Metritape, Inc.)

4.7 Lightning Protection For Bulk Storage Tanks

The National Fire Protection Association (NFPA)* Publication No. 78 "Lightning Protection Code 1977" provides detailed information on the topic under discussion. Additional information is provided in the American Petroleum (API)** Publication RP2003-10/74 "Recommended Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents."

The voluntary codes contend that the contents of metallic tanks with steel roofs of riveted, bolted, or welded construction used for the storage of flammable liquids at atmospheric pressure are protected against lightning (inherently self-protecting) under the following conditions.

"(a) All joints between metallic plates shall be riveted, bolted, or welded.

(b) All pipes entering the tank shall be metallically connected to the tank at the point of entrance.

(c) All vapor or gas openings shall be closed or provided with flame protection, when the stored stock may produce a flammable air-vapor mixture under storage conditions.

(d) The metal roof shall have a minimum thickness of 3/16 inches (4.8 mm).

---

*NFPA, 470 Atlantic Avenue, Boston, MA 02210
**API, 1801 K Street, N.W. Washington, D.C. 20006

(e) The roof shall be welded, bolted, or riveted to the shell."

To gain a maximum degree of protection, however, it has been observed that most bulk storage facilities still provide grounding protection.

Specialists in the field recommend that there be at least two points to ground, one on opposite sides of the tank. Ground terminals (rods) of not less than 1/2 in. (12.7 mm) diameter are driven at least 8 ft. (2.4 m) into the earth at a position 2 to 3 ft. (.6 m to 1.02 m) away from the tank. The rods are either copper-clad steel, solid copper, or stainless steel. The protective systems demand that bonding plates be welded to the tank at each grounding location and that a No. 6 gage copper wire be attached to each bonding plate and ground rod. The grounding wire should contact the rod and the ground cable for a distance of 1 1/2 in. (38 mm).

In soil less than 12 in. (0.3 m) deep the structure should be surrounded with a main-size conductor (a counterpoise) laid in trench or in rock crevices. From this counterpoise, a conductor should be run to pits or hollows where added metal can be deposited. Approximately 9 sq. ft. (0.84 m^2) .032 in. (0.8 mm) thick of copper plate of equivalent corrosion resistant metal should be connected to the lateral conductors. The installation should be covered with loose earth for rain absorption.

4.7.1 Floating Roof Tank Lightning Protection

Tanks of this design require special attention. Fires have occurred when lightning struck the rim of a tank at a time when the roof was high and the content volatile. Fires have also been started when the roof was in a low position and, due to a defective floating roof seal, accumulated vapor above the roof were ignited by a rim strike.

The best defense is to maintain a tight roof to tank shell seal. Additionally when the floating roof utilizes hangers within the vapor space (Figure 4- 28) the roof should be electrically bonded to the shoes (sealing ring) of the seal through

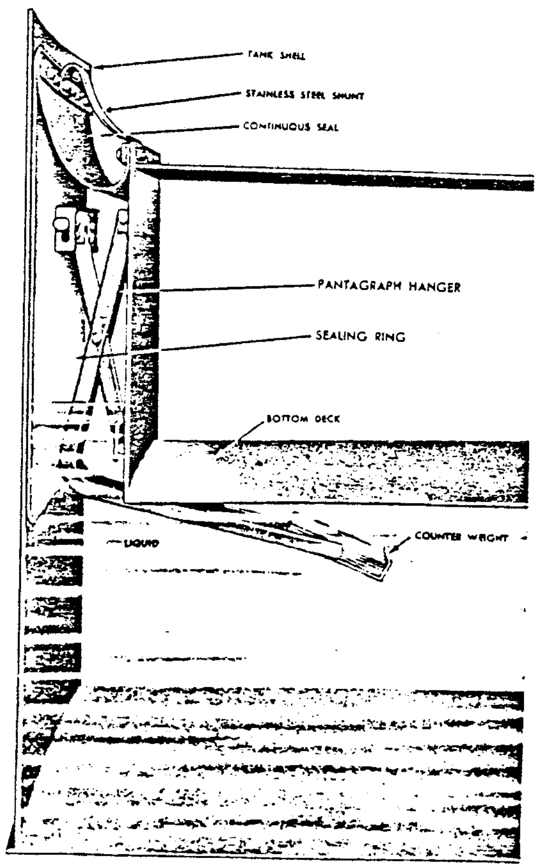


FIGURE 4- 28 Floating Roof Hanger
(Illustration Courtesy CBI)

the most direct electrical path at intervals of not greater than 10 ft. (3 m) on the circumference of the tank. These shunts should consist of flexible Type 302, 28-gage (1/64 in/ 0.4mm) x 2 in. (51 mm) wide stainless steel straps, or their quivalent in corrosion resistance and current-carrying capacity.

In some cases whereby the floating roof tank has a telescoping ladder connected to the tank shell that rests and rides onto the floating roof, the ladder can be designed to provide a roof to shell ground connection.

4.7.2 Ground Resistance Measuring

Following provision of a grounding system, the installation should be subjected to ground resistance and soil resistivity testing on at least a regular annual basis. A reading of 25 ohms should be maintained.

A typical testing unit is manufactured by the AEMC Corporation of Boston, Massachusetts. The "Terracontrol" unit manufactured by this concern is depicted in Figure 4- 29 . The principle of operation can best be described by verbatim reproduction from the manufacturer's Bulletin #B130.100 and B132.100.

The model as illustrated sells complete for $616 and a smaller unit, Model B130.100, sells for $406 (7/80).

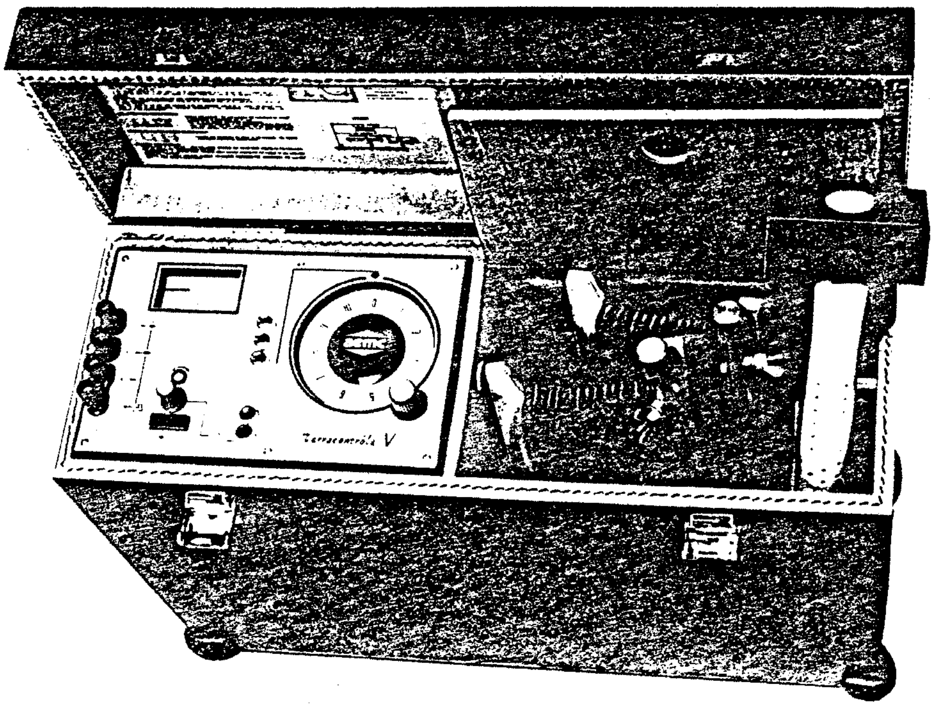


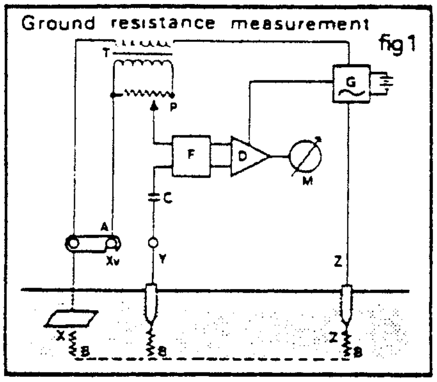
FIGURE 4-29.

Model #B132.100 "Terracontrol"
Electronic Ground Tester

Illustration Courtesy
AEMC Corporation, Boston, MA

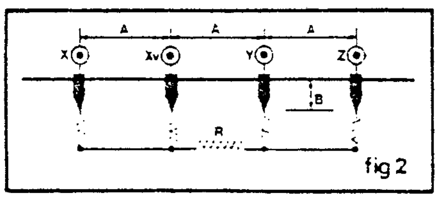
Principle

1° Ground resistance measurement (fig. 1).



When ground resistance is to be measured, the terminals X and Xv are short circuited and Y, Z are auxiliary electrodes.
A solid state generator G, supplied by six 1.5 V AA dry cells, produces a 225 Hz current sent into the circuit GZBXT. The voltage VX at X between A and B is compared to the voltage VP (produced by the transformer T and its potentiometer P) between A and P.
The resulting voltage VR (VX-VP) is applied to a synchronous amplifier, which supplies the zero galvanometer M.
The balance is obtained by adjusting P so that VR equals zero. The ground resistance is then displayed on the 245 mm (9.64 in) dial 0–10 scale (200 divisions) which is connected to the potentiometer P.
The primary of T has three inputs and gives three ranges 10 - 100 - 1,000 Ω.

2° Soil resistivity measurement (fig. 2)



The TERRACONTROL can be used for finding the best place to bury ground grids, to place ground mats and ground electrodes, as well as for geophysical prospecting.
In these cases, the strap between X and Xv is disconnected (fig. 2) and 4 electrodes are respectively connected to X, Xv, Y and Z. The basic measuring principle is the same as before, but the resistance R between Xv and Y is measured. The resistivity can then be obtained by using the following formula (Wener formula):

$$\rho = \frac{4\pi AR}{1 + \frac{2A}{\sqrt{(A^2 + 4B^2)}} - \frac{2A}{\sqrt{(4A^2 + 4B^2)}}}$$

Where: A = distance between the electrodes in centimeters.
B = electrode depth in centimeters.
if: A > 20 B the formula becomes :
$\rho = 2\pi AR$ (with A in cm).
$\rho = 191.5\ AR$ (with A in feet)
ρ = Soil resistivity
This value is the average resistivity of the ground at a depth equivalent to the distance A between two electrodes.

3° Non inductive resistance measurement

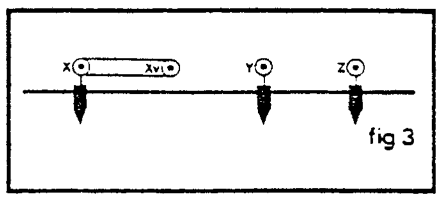
The TERRACONTROL can also measure a non inductive resistance or an electrolyte. The set-up is as in fig. 1, the resistance to be measured is placed between X and YZ (Y,Z are connected).

Field Use

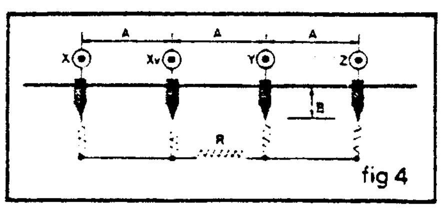
Both Terracontrols are designed for field use. They are fitted in rugged leatherette covered plywood carrying cases.

Connections

1) Ground resistance.
Short circuit the terminals X, Xv with the shorting link.
Connect the ground to be measured to terminal X, use the 5m (15 foot) lead. Connect the auxiliary rods to the terminals Y and Z. Use the two 20m (60 foot) leads. (See fig. 3)



2) Soil Resistivity.
Use all four terminals, and separate all four test rods by an equal distance. (See fig. 4)



Note: Taken verbatim from AEMC Corporation sales literature

REFERENCES

Section 4.7

"Recommended Practice For Protection Against Ignitions Arising out of Static, Lightning and Stray Currents" API Bulletin RP2003 Third Edition. October 1974.

"Lightning Protection Code 1977" NFPA Bulletin 78.

4.8 Tank Draining

4.8.1 Water Drain Valves

Water drain valves are located in the lowermost section or shell of a bulk storage tank. The valve is usually small in diameter and an internal drain line goes from the valve down into the lowest possible reach of the tank's lower head. The valve is used to drain water accumulation from the tank. The water collects in the tank bottom from floating roof drains, condensation and from water that may have entered and contaminated the product during transportation, especially during marine transport. On a regular frequency, determined by humidity and other atmospheric conditions, the water is drained from the tank through the medium of the water drain valve. It is standard practice to keep these valves in the padlocked closed position. This is not always the case, however. Padlocks are frequently missing, laying on the ground near the valve, or in some cases, placed back in the valve in an unlocked status.

It is stressed that the water drain valve, after improper opening of a masterflow control valve or tank failure, presents the greatest potential for draining and completely emptying the contents of a tank. As recently as September 9, 1980 a 137,000 gallon spill of No. 2 diesel oil was experienced in a Baltimore, Maryland bulk storage facility. It was found that the locking chain on a water drain valve had been cut and the valve opened on a 4 million gallon storage tank. As the drain valve in the dike had also been sabotaged the oil drained to an oil and water separator having the limited capacity of 250 gallons per hour. The oil overflowed the system and drained into a creek which emptied into Baltimore Harbor.

4.8.1.1 Controlled Drainage Systems and Piping

At many locations the operational practice is to drain the accumulated water directly into the diked enclosure. When this is done the operation requires constant attention since when the tank has been drained free of water, the product within the tank begins to drain. The possibility of this happening is high. Water drainage can be a lengthy process which can vary from two hours to two days during some seasons of the year. In such cases, the attention of a worker can be diverted and incidents are recorded whereby workers have actually forgotten they opened the valves and recalled the opening after leaving work. Product has been lost with massive spills escaping into diked areas and into nearby waterways.

In a serious effort to control such losses industry has begun to pipe these valves into wastewater treatment ponds, into oil and water separators, and in some instances, into oil retention sumps. The first two practices are preferable due largely to their having increased capacity over an oil retention sump as normally installed in a plant's storm water drainage system. It is, however, possible to install on audible/visible oil spill detection alarm either in the sump itself or at any convenient location in the drainage system.

4.8.1.2 Dow Imbiber Valves

The Dow Chemical Company, Midland, Michigan has developed an alternative system that permits drainage of a tank's water content into the diked containment area, at the same time insuring that certain hydrocarbon products will not leave the tank. The "Imbiber Valve," a product produced by Dow, is designed for attachment on the discharge of the water drain valve. It will restrain the flow of gasoline, benzene, toluene, xylene, ethylbenzene, styrene, polychlorinated biphenls (PCB's), and 1, 1, 1, trichlorethane. The manufacturer's directions for use are as follows:

1. Attach pipe adapter to water drain valve.
2. Drain any oil entrapped in draw-off into suitable container.
3. Attach Dow Imbiber Valve to water drainoff adapter and tighten (hand tight) against gasket.
4. Open water draw-off valve to allow flow through Imbiber Valve.
5. When flow ceases, indicating contact with water/oil interface, close water draw-off valve (See note).
6. Remove Imbiber Valve and discard in proper manner.

Note: Occasionally, oil dissolved in the water layer may prematurely activate the Imbiber Valve. If this occurs, close draw-off valve, replace Imbiber Valve with a fresh unit and resume water draw-off.

The instructions indicate that the unit is disposable. However, valves are available that utilize a disposable cartridge designed to fit within a sturdy, permanent housing. Figure 4-30 depicts the configuration and integral parts of a disposal Imbiber Valve. The cost of these valves is within the following ranges when ordered in varying quantity:

IMBIBER VALVES Shipping Class NMFC #14500:

XFS-43094 Imbiber Valve	up to 10 boxes	$72.00/box
12 units/box	11 - 75 boxes	66.00/box
Label License for U.S. 3,750,688	over boxes	60.00/box
XFS-43095 Imbiber Valve Adapter	per box	10.00/box
2 units/box; 60 boxes/case	60 - 120 boxes (1-2 cases)	7.00/box
	over 120 boxes (over 2 cases)	6.50/box
XFS-43096 Imbiber Valve Adapter Gasket 12 units/film bag	per bag of 12 units	2.00

IMBIBER CARTRIDGES Shipping Class NMFC #14500:

XFS-43109 Imbiber Cartridge (Diesel)	up to 10 boxes	70.00/box
in boxes of four units	11 to 50 boxes	63.00/box
Label License for U.S. 3,750,099	over 50 boxes	54.00/box
XFS-43139 Imbiber Cartridge-G (Gasoline)		
in boxes of four units	up to 10 boxes	70.00/box
Label License for U.S. 3,750,088	11 to 50 boxes	62.00/box
	over 50 boxes	54.00/box

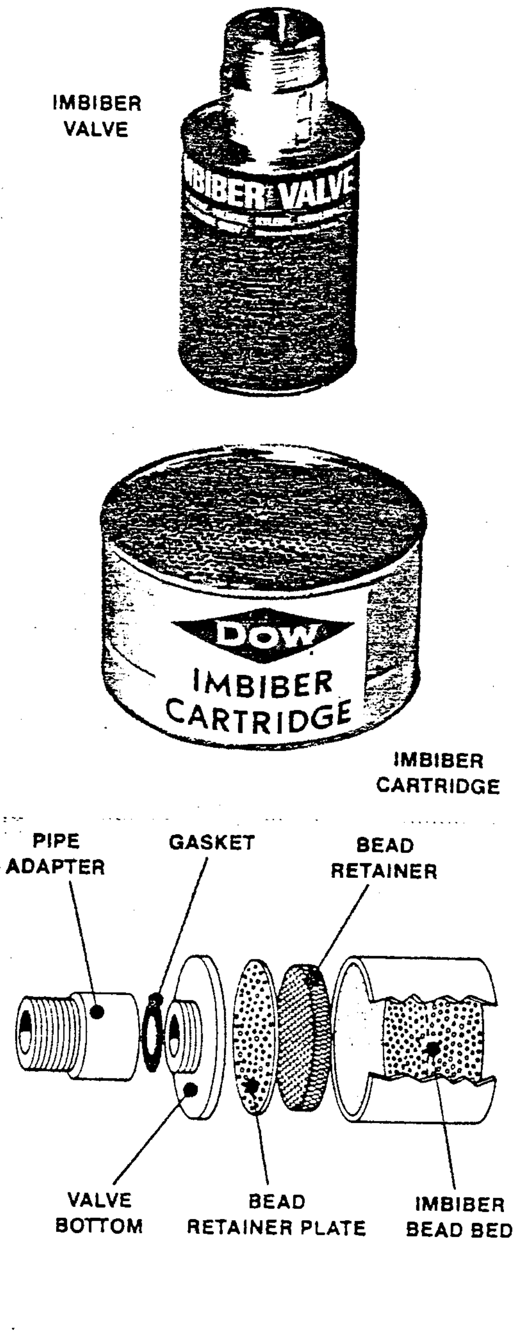


FIGURE 4-30.
Configuration of Imbiber Valve
(Illustration Courtesy The Dow
Chemical Company)

XFS-43110 Imbiber Housing	up to 10 units	97.00/ea.
in boxes of one unit	over 10 units	92.50/ea.
XFS-43111 Imbiber Cartridge Gasket Set	1 - 10 sets	3.50/ea.
1 set of 2 per envelope	11 - 49 sets	3.25/ea.
	over 50 sets	3.00/ea.

All prices FOB Midland, MI 48640
Prices subject to change without notice

Send inquiries to:

Imbiber Systems
Functional Products and Systems
2020 Dow Center
Midland, MI 48640

Minimum Order: $50.00

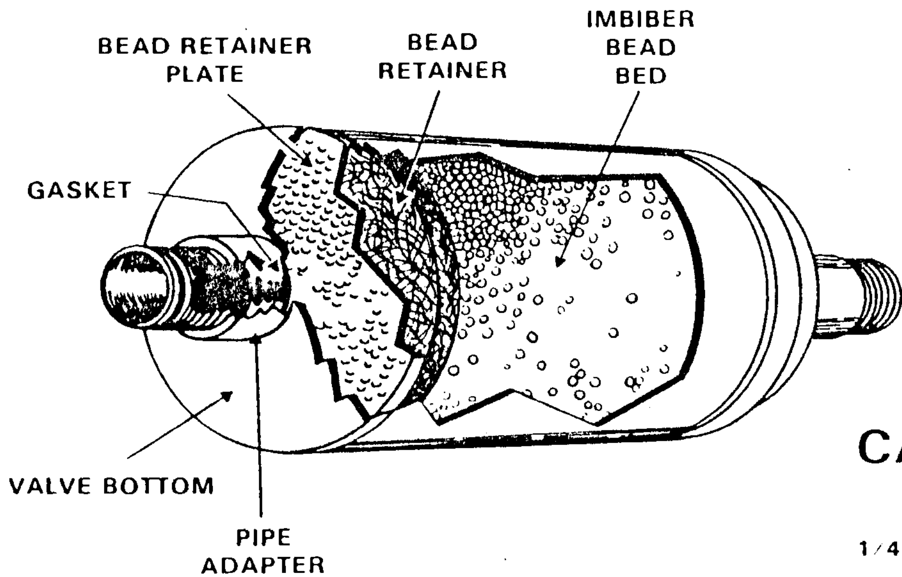
Figures 4-31, 4-32, and 4-33 illustrate the valves and their applications.

4.5.1.3 Security

Water drain valves should be locked at all times when not in service. The opening and closing of the valves should be under strict supervisory authority. Frequent inspections should be made of the valves to see that the security of the valve has not in any way been violated.

ORIGINAL IMBIBER VALVE

(Screw-on Canister)



CARTRIDGE IMBIBER VALVE

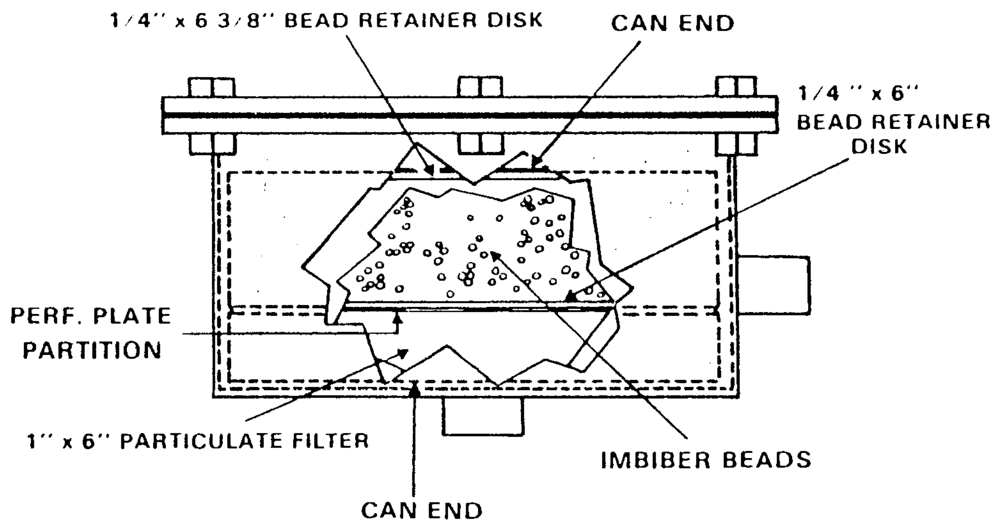


FIGURE 4-31. Original and Cartridge Imbiber Valves
(Photograph Courtesy Dow Chemical Co.)

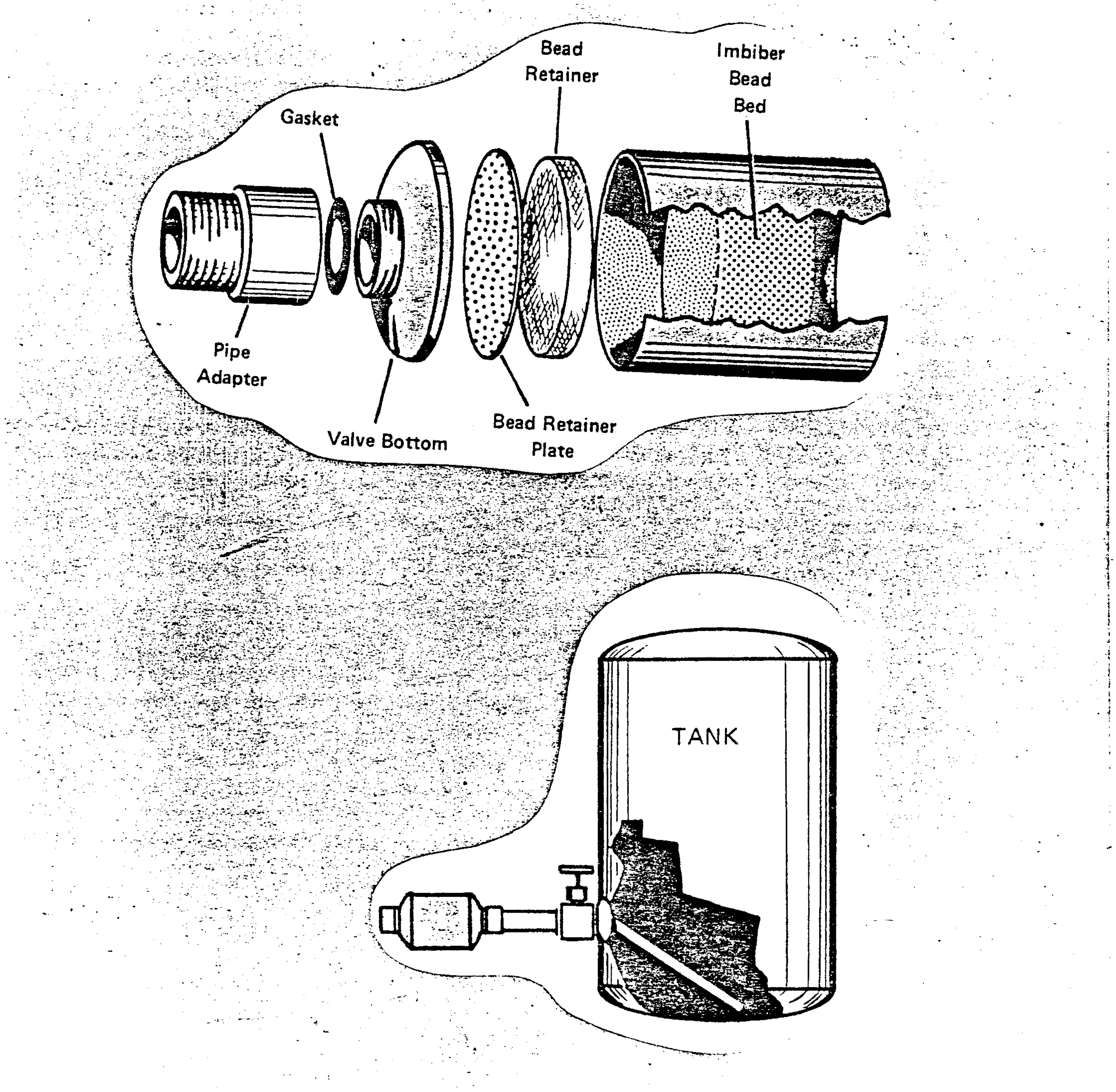


FIGURE 4-32. Dow Imbiber Valve and Method of Installation (Photograph Courtesy Dow Chemical Co.)

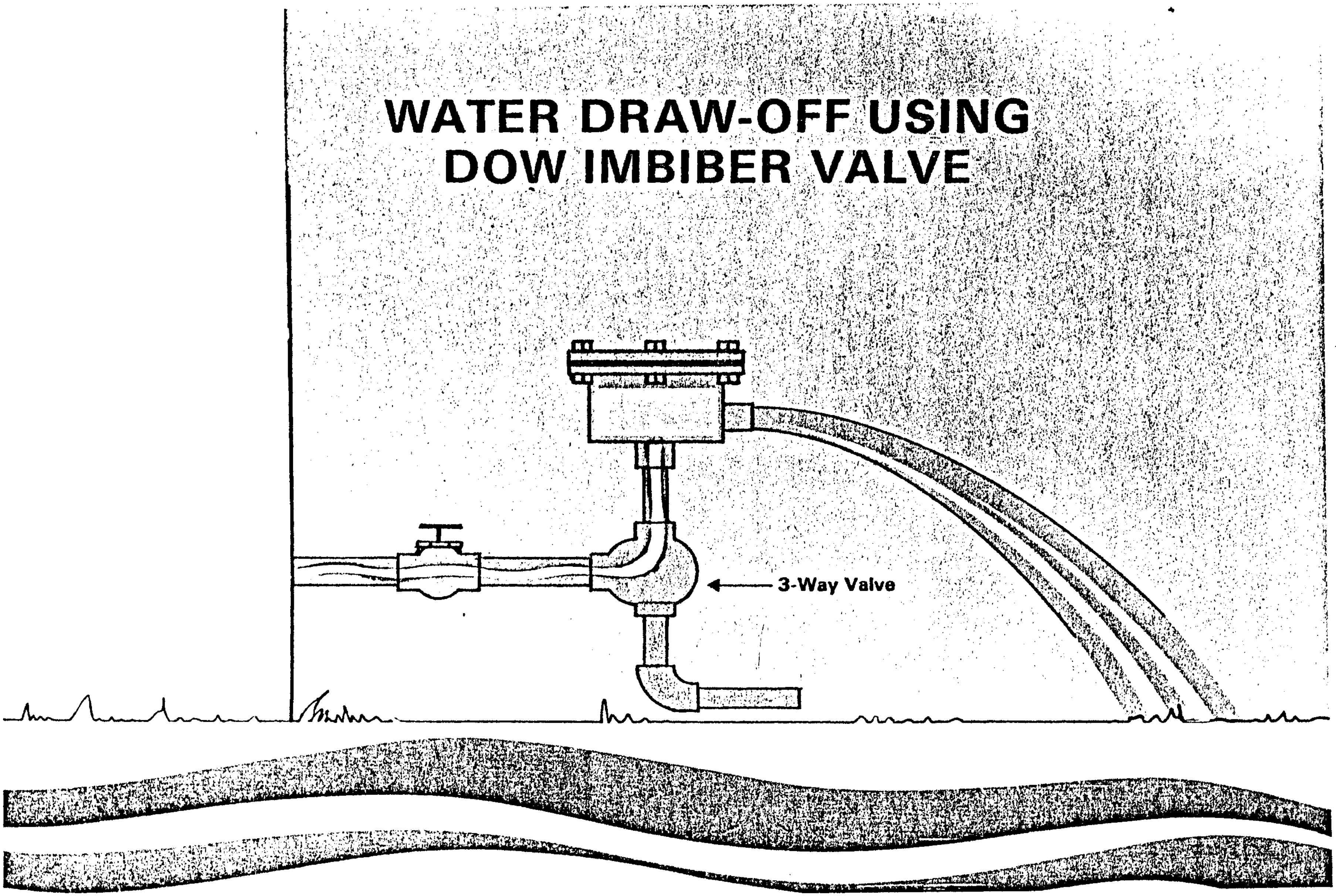


FIGURE 4-33. Water Draw-Off Using Dow Imbiber Valve
(Photograph Courtesy Dow Chemical Co.)

4.9 General Procedures for Spill Containment

4.9.1 Field Observations

Many tank farms are so large that the storage tanks are seen very infrequently. In some oil fields the tanker man fills the tanks through the medium of a timer, a telephone, and an intimate knowledge of the pumping rate and the tank capacity. This fill procedure is of course aided by computerized liquid level gaging systems. There is a need, however, for regular inspection of the tanks and their appurtenances. Leakage can occur from tank seams, valve connections, valve stems, and pipeline joints. This can only be determined from visual examination as the quantity of product lost is too small to be registered by remote gaging systems. For this reason each tank should have at least monthly inspection. In this respect it is insufficient just to walk the dike and examine the tank from a distance. The inspector should enter the diked area and examine the storage container from grade level, following which the tank top should be visually examined. All valves and pipelines within the diked enclosure should be visually surveyed to determine defects or signs of external deterioration. The tank foundation and metal-to-concrete seal should have special examination since a defective seal can permit rain water to collect under the tank and corrode the bottom head-sight unseen.

4.9.2 Tell-Tale Signs of Failure

Seams and rivet leakage in older tanks results in tell-tale streaks of product down the tank side. The same can be said of welded seams that have a high degree of porosity (actually poor welding).

Bolted cleanout openings can also be leak sources through a deteriorated or poorly made gasketed joint.

Valve stem packing can also produce steady leakage due to full compression of the packing, inadequate packing or from physical damage during the opening and closing process.

Settling of pipeline supports can produce a void between the pipe and the support. When this occurs, lack of support can place undue stresses on the unsupported line.

Spalling of the tank's concrete foundation and general deterioration, such as drying out and cracking of the tank's bottom flange bitumastic seal, are two further indications of general deterioration.

Weed overgrowth should be examined and prevented. Excessive weeds within the diked area present a fire hazard that eliminates a needed fire break. Surveys have revealed 10 ft. tall trees within a diked enclosure--such growth cannot be tolerated.

As far as practical, the earth within the diked enclosure should be crowned to drain rainwater away from the tank. As stated elsewhere in this manual, conditions have been viewed whereby all rivet heads in the lowermost seam of an older tank were corroded away from standing in floods of rainwater.

4.9.3 Placarding

For a variety of reasons, including industrial espionage, industry does not like to indicate what product is stored within a particular container. This information can, however, be desperately needed by a fire department when fighting a fire. In the petrochemical field the name alone does not aquaint the firefighters with the hazards associated with a particular petrochemical. For this reason the Federal government through the U.S. Department of Transportation has adopted a series of symbols to denote classes of hazards associated with groups of chemicals. The symbols are internationally recognized for use on hazardous material labels. Persons coming in contact should recognize the symbols and the potential hazard they represent regardless of the symbol color. The wording on the label may be in English or in the language of the country of origin. Figure 4-34 graphically portrays the governmentally accepted symbols.

It should be noted that The Code of Federal Regulations, Title 49, Part 100-199 contains the regulations for preparation and transportation of hazardous materials by rail, air, vessel, and public highway.

It is strongly suggested that the symbols be used in oil and petrochemical facilities to denote the chemicals stored in bulk containers including process vessels.

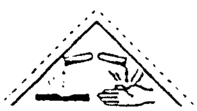
SYMBOLS	UN CLASS NUMBER	DOT HAZARD CLASSES	COLOR OF LABELS
	1	Explosive A Explosive B Explosive C	Orange
	2	Non-Flammable Gas	Green
	2	Flammable Gas	Red
	3	Flammable Liquid	
	4	Flammable Solid	White & Red Stripes
	5	Oxidizer	Yellow
		Organic Peroxide	
	2 or 6	Poisonous Material- { Poison A Extremely Toxic Gas or Liquid Poison B Highly Toxic Liquid or Solid	White
	6	Irritating Material - The symbol is not required on domestic shipments.	"Irritant" in Red Letters on White for domestic shipments. Black for export shipments.
	6	Etiologic Agent - { Infectious material - Microorganism or Toxin that may cause human disease	Domestic: Red and White Combination Export: Black and White Combination
	7	Radioactive Materials- (Slight variation in label according to Radiation Levels) { If released, presents radiation and contamination hazards	White I-Red bar Yellow/White II-Red bars Yellow/White III-Red bars
	8	Corrosive Material	Upper Half-White Lower-Black
		Combustible Liquid	No Label Requirement
ORM-		ORM-A	No Label Requirement Refer to Title 49, CFR, Sec. 172.316 for the appropriate ORM designation.
		ORM-B	
		ORM-C	
		ORM-D	

FIGURE 4-34.

U.S. Department of Transportation
Hazardous Materials Warning Labels

4.10 Secondary Means of Containment and Diked Enclosures

Earthen dikes (berms), retaining walls, and curbs fall into the category of secondary means of containment to impound spill from bulk storage tanks or processing tanks. The enclosures should effectively contain spillage, overfill and the entire content of the largest tank within the enclosure. Earlier in this section of the report an incident was described in which tank failure followed by a sudden release of the entire tank content physically washed away a spill retention dike. On the basis of incidents such as this dike design and construction becomes a most important spill retention factor. Hitherto, dike construction largely consisted of mechanically pushing fill material into position to provide an earthen barrier around one or more tanks. For the most part the permeability of the material mattered little, or was completely ignored. Frequently erosion would greatly reduce the effective height of a dike. During construction activities a dike would be breached to permit the entry of construction equipment and the integrity of the dike could be violated for many weeks.

Some storage containers are surrounded by a concrete block wall. However, this form of containment has never been satisfactory for a number of reasons:

1. Settling separates the blocks and, in some cases, cracks them destroying the integrity of the containment wall.

2. Spalling of the mortar between the blocks can destroy the liquid-tightness of the wall.
3. It is difficult to construct a liquid-tight wall from concrete blocks due to their porosity and the vulnerability of mortared joints.

Poured concrete walls are a preferable type of construction.

In older plants limited space, or the confined location of existing tanks, prevents the installation of dikes, barrier walls, or curbs. Such a situation warrants engineered drainage that will direct spilled material to an adequately sized impoundment pond or other temporary storage area.

It is also standard practice to maintain the impoundment area free of water accumulation that would reduce it's holding capacity. On this basis a pumping system is generally warranted. The exception would be when the spilled material is directed into an operational waste treatment pond capable of holding the spilled material in addition to its normal effluent content. The impoundment should also be lined with concrete, impermeable clay, or a synthetic membrane, to prevent percolation through the earth down to ground water. NFPA further recommends that the slope away from the storage tank be from an elevation of +.5 feet to grade 50 feet away in the direction of the impoundment site.

Returning to diked areas, as with impoundment ponds, the diked enclosure should effectively contain the content of the largest tank in the protected area. To prevent seepage and spill percolation, many industrial plants are installing a veneer of impervious clay or a layer of Gunite® cement over the contained land area. Gunite® is a sand cement mixture which is pressurized through a pneumatic gun onto prepositioned reinforcing steel. The force of application by the use of compressed air develops a piling effect of the larger particles and a dense impervious mass results having a minimum of entrained air. The proper mixture of sand cement and water promotes extreme strength, hardness and an abrasive resistant surface having a compressive strength that has been tested to 6000 psi and greater after a setting period of 28 days. The density and liquid-tight qualities of Gunite® allows an application to withstand conditions which ordinarily destroy or damage conventional concrete. It has been successfully used for structures exposed to alkalies, acids, salt water and certain corrosive fumes. The cost of application varies by state and contractural organization. It can be closely estimated, however, that a 4 in. thick application pressured into position over #8 reinforcing wire would cost in the vicinity of $3 per square foot. Figure 4-35 illustrates a typical method of Gunite® application.

One of the advanced methods for soil treatment and stabilization has been developed by the Japanese. Takenaka Komuten Co. Ltd. headquartered in Osaka, Japan has developed the Takenaka deep chemical mixing (DCM) method for ground

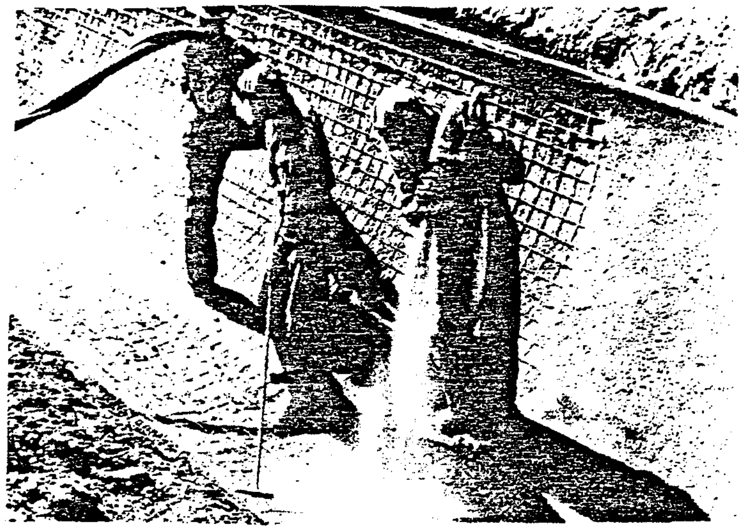


FIGURE 4-35. Applying Gunite Cement
Helper lifts reinforcing to insure that Gunite[R] gets behind it, leaving the mesh in the center of the lining for strength and freedom from leakage.
(Photograph Courtesy Allentown Pneumatic Gun Company, Allentown, PA)

soil solidification at deep strata. With the DCM technique soft ground formed by natural deposition is solidified in-situ. The solidifying chemicals with the addition of water are mixed into slurry form and pumped to the area to be treated using an oil pressure pump. It is then mixed with soft ground over the depth needed to be solidified. This technique effectively "locks" existing pollutants in place.

An additional treatment has been developed by the American Colloid Company, Skokie, Illinois known as "Volclay." By the application of a veneer of high swelling Volclay bentonite pourous soil can be made impermeable. The Volclay mineral is raked or disked into the top soil and rolled. The

Volclay increases in size when contacted by water jambing itself into voids in the soil. Volclay is a natural bentonite clay product with the same constituents as other clays, but with a unique molecular structure which permits it to absorb many times its weight in water. In doing so, Volclay swells up to 15 times its dry bulk when fully wetted. This wetting is reversible and Volclay can be dried and reswelled an infinite number of times. In extreme cases where severe ground movement would rupture the soil or a foreign object would penetrate it. Volclay particles will migrate to with the seepage flow to affect a resealing action.

4.10.1 Dike Construction and Erosion Control

Dikes are generally raised to a height of around 6 ft. and normally are flattened on the top to provide a 2 ft. wide walkway. The slope of the dike should be consistent with the normal angle of repose of the soil from which the dike is constructed.

Erosion protection can be gained by covering the dike with a layer of Gunite^{R} cement at least 4 in. in thickness complete with a layer of reinforcing steel as previously described. The covering also aids in developing a liquid-tight containment barrier. In recent years this has been supported by building dikes that have an impervious base and internal core. Figure 4-36 denotes how Volclay soil sealant might be used for impermeable dike construction. However,

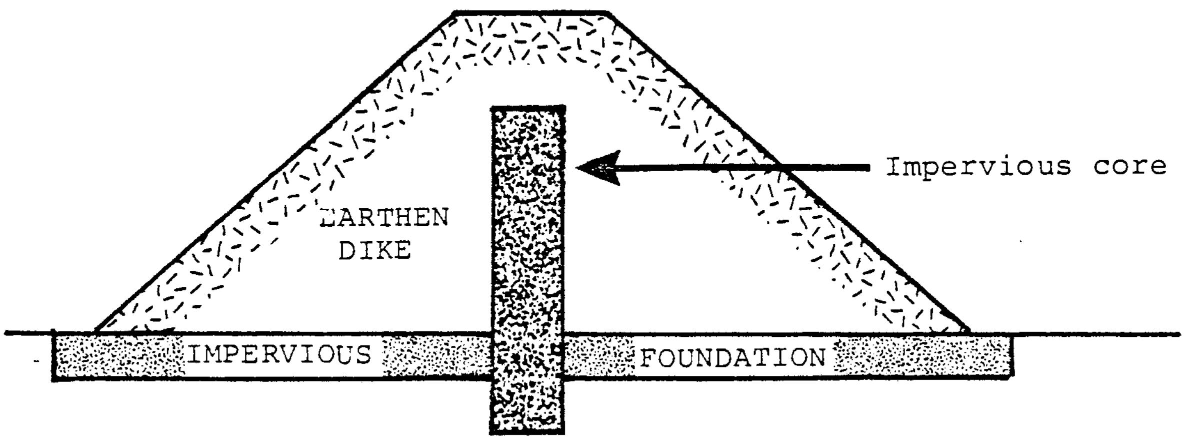


FIGURE 4-36. Impervious Dike Construction

dikes are presently being constructed with a poured concrete base or foundation and a central concrete impervious core. To a certain extent synthetic membranes have been used to develop a liquid-tight barrier. Alternatives to a cement covering over the surface of the dike include steel plates positioned and secured permanently over the earthen surface. Some oil handling facilities have sprayed the external surface of the dike with a bitumastic/alphatic coating that hardens in position. A concrete dike based on delivered concrete at \$30 - \$48/yd^3 would cost about \$50 to \$70/yd^2. A gabion protected dike would cost around \$40 to \$70/yd^2. Rip-rapped rock protection would cost \$25 to \$50/yd^2 of surface.

From a beautification standpoint erosion control can be gained through the medium of mulching blankets manufactured by Erosion Control Systems, Gulf States Paper Corporation, Tuscaloosa, AL (205/553-62000, Ext. 427). The blankets consist of a knitted construction of polypropylene with uniform openings interwoven with strips of biodegradable paper fill. Prior to positioning the mulching blanket, topsoil should be spread over the dike surface and grass seed should be spread into the topsoil. The erosion control blanket is installed immediately after the seeding operation. The blanket, available in 5 feet x 360 feet or 10 feet x 360 feet lengths, is then spread over the prepared surface unrolling the blanket parallel to the direction of flow, without folds or stretching so that continuous ground contact is maintained.

On slopes, each upslope and each downslope end of each piece of blanket should be placed in a 4 inch trench, stapled on 12 inch centers, backfilled and tamped. Where one roll ends and a second roll starts, the upslope piece shall be brought over the end of the downslope roll so that there is a 12 inch overlap, placed in 4 inch trench, stapled on 12 inch centers, backfilled and tamped.

On slopes where two or more widths of blanket are applied, the two edges shall be overlapped 4 inches and stapled at 12 inch intervals along the exposed edge of the lap joint. The body of the fabric should be stapled in a diagonal grid pattern, with staples three feet on center each way.

If any staples become loosened or raised, or if any fabric comes loose, torn or undermined, repairs should be made immediately. If seed is washed out before germination, the area shall be refertilized, reseeded and otherwise restored.

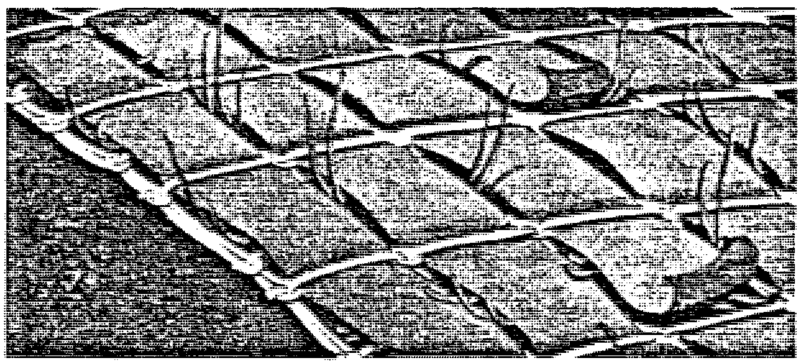
The staples used to position the blanket are fabricated of 11 gauge wire, "U" shaped with a 1 inch crown and 6 inch legs. They can be manually pushed into the earth. Figure 4-37 illustrated the principal of the operation and the erosion control techniques. Figure 4-38 depicts the method of applying the mulching blanket over a steeply sloped surface. The cost of the described process on a 3.4:1 grade can vary, depending on the type of seed selected, from 35¢ to 60¢/yd^2. By comparison, the laying of started sod on a 3:1 slope would be in the vicinity of \$2.50 to \$3.40/yd^2 and a hay mulch seeding with a jute protection sheet would cost \$1.25 to \$1.50/yd^2.

4.10.2 Drainage of Diked Areas

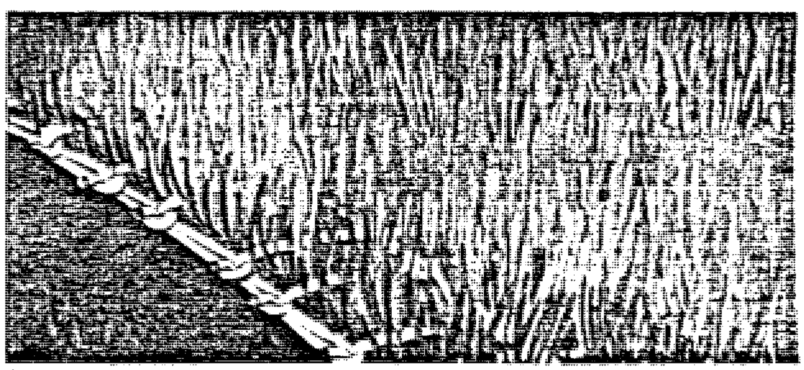
There are a number of undesirable ways of draining rainwater from diked areas. Field observations at one location revealed an interconnected drainage system from one diked area to another. This to the extent that the drainage from an adjoining unowned facility was also interconnected into the system. The terminal control valve on the system was left in the open position violating the integrity of the entire spill retention system. Furthermore, an overfill of oil from any tank would have the opportunity to travel over a great area--from one diked area to the other.

The beginning of erosion: raindrops act as tiny bombs.

Hold Gro shields ground from rain's explosive force. Then lets moisture seep through.



Paper acts as mulch to hold moisture in, degrades as new growth begins.



After paper degrades, the yarn temporarily supports the root structure

FIGURE 4-37.

Operation of Mulching Blanket for Dike Erosion Control - From Gulf States Paper Corp.

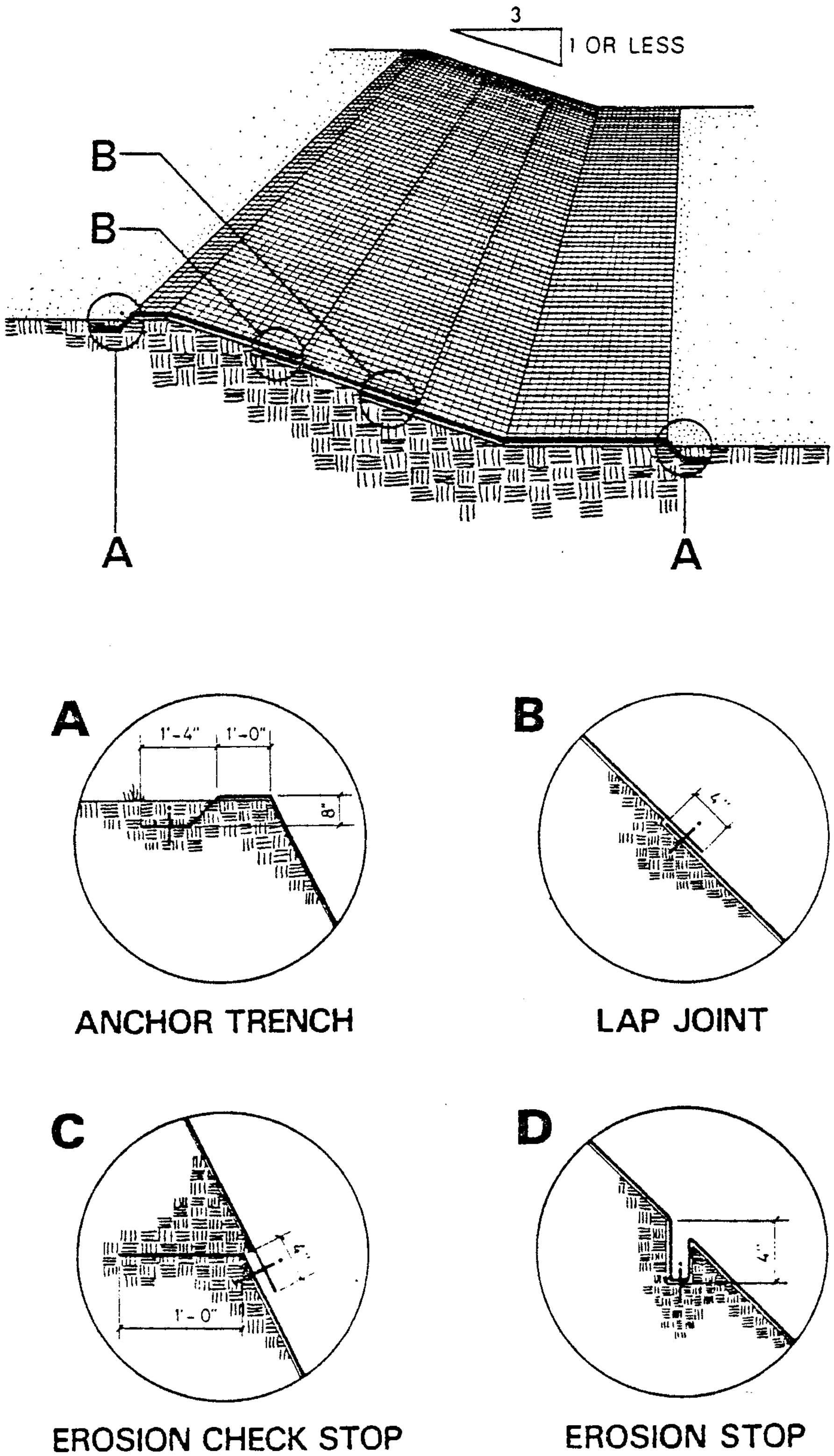


FIGURE 4-38.

Mulching Blanket Application Techniques
From Gulf States Paper Corporation.

At another large oil handling facility in New Jersey, the plant relied on dropping a large sandbag plug into an open drainage line. This manual plugging would demand that a worker pass through oil to restrain a spill. Until detected the oil could flow freely to an oil/water separator that might not have the capacity to separate a large spill of oil.

A plant in the Boston area used (note past tense) flap type valves to drain their diked areas. The procedure of draining required a worker to walk the dikes after a rainstorm to open the flap valves. They were positioned at grade level within the restrained area. Through the medium of a pull cord that passed through an elevated sheave on the crest of the dike, the flap valves could be opened or closed. Human failure to close the valve after a drain action was always prevelant. However, a major spill (200,000 gal. #2 fuel oil) occurred when a massive overfill escaped through a flap vlave which was partially open due to a displaced stone lodged under the flap valve.

The best possible action to avoid accidental oil leakage is to eliminate all drains from the area. This may appear as a severe demand although one of the major (and cleanest) chemical processors has already instigated this action. Management contends that they prefer to first test the accumulated rainwater for pollutants, then portable pumps are used to transfer contaminated water into tank trucks and "clean" water into the storm drainage system.

The basic prevention system within the majority of plants is to maintain rigid control over the opening and closing of drain valves from diked areas. The valves are maintained in the locked-closed position. The key for the valve lock and the decision to drain rests with a selected supervisory person such as the maintenance foreman, or operational superintendent. Prior to draining, the water quality is assessed for contamination, oil sheen and the like. Once determined as "clean", draining is undertaken with a worker on constant standby. After draining is completed, the valve is locked by the supervisor and the date of draining is recorded in a time log as a protection against an unjust accusation of causing a sheen on any navigable waterway. Even this action can be improved upon by draining the water through an oil and water separator before final discharge. An added improvement would be to first drain the water through a bed or filter of sorbent material such as Dow Imbiber Beads. The beads provide a sorbent for hydrocarbons (oils), aromatic hydrocarbons (benzene, toluene), and Polychlorinated Biphenyls (PCP's). The beads are cross linked polymers of alkylstyrene which has the capacity to absorb a large quantity of fluid without becoming completely dissolved. This holds true even with an excess of the fluid absorbed. As the beads imbibe fluid, they swell in size and fluid is entrapped by the molecular structure of the bead. There is no leaking from the bead which, being oleophilic*, will permit the free flow of

---

*Treated to attract oil

water until contacted by an oily material. Figure 4-39 graphically displays the function of an oleophilic sorbent filter.

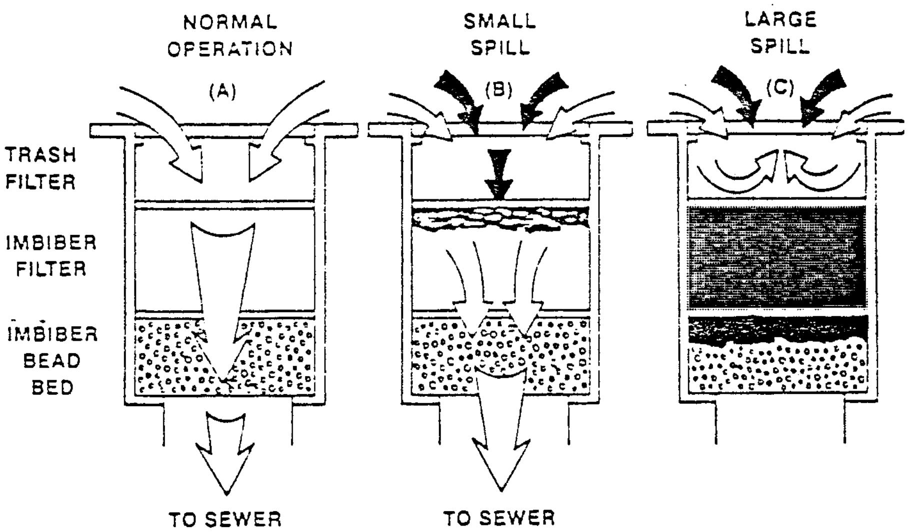


FIGURE 4-39.

Dow Imbiber Bead Filter Unit
(Illustration Courtesy of The Dow Chemical Company)

4.11 Tank Cleaning and Sludge Disposal

4.11.1 General

Most large organizations being cognizant of the hazards of tank cleaning maintain a special tank cleaning crew that travels from plant to plant cleaning tanks on a regular frequency.

Unless adequate safety and industrial hygiene precautions are exercised, the accident exposures developed from tank cleaning are extremely high. To fortify this statement and to indicate the risks involved, the following incident is related.

The foreman of a tank cleaning crew arrived at a Tampa, Florida worksite early; it was in fact, dark. The tank's retention dike had been broached and the worker entered the diked area in his pickup truck. To expedite the cleaning process he decided to open one of the tank's cleanout doors. This entailed removing a large number of nuts that held the gasketed plate in position; the foreman turned on his truck's headlights to gain illumination. As work progressed, the lights drew down the truck battery until the lights began to dim. At this stage the worker turned on his engine to brighten the lights and charge the battery. Immediately upon turning the ignition key, an explosion occurred which demolished the empty tank, severly injured the worker, and practically demolished his vehicle. The explosion was later attributed to vapors escaping from the loosened cleanout access door which were ignited from a spark from the truck's ignition system. Luckily none of the nearly full storage tanks were damaged by the blast and a massive spill was avoided.

There are multiple hazards associated with the cleaning operation. The exposures include:

1. Possible explosion and resulting fire.
2. Lead exposure to tank cleaners when loaded gasoline tanks are cleaned.
3. Lack of oxygen for workers entering the tank.
4. Toxic vapor inhalation.

5. Skin sorbtion, burning, and/or irritation from contact with gasoline, etc.
6. In tanks used for the storage of sour stocks and crude oil having high sulfur content there is an exposure from inhaling hydrogen sulfide (H_2S). H_2S is a colorless, toxic malodorous gas having a threshold limit value of not more than 10 ppm for any 8 hours of work exposure.

4.11.2 Personal Protective Equipment

The use of protective clothing preferably fabricated of oil resistant rubber or vinyl is important for personal safety. Positive air pressure respiratory equipment should also be provided for use by tank cleaners. The masks should provide full fast protection. Additionally, there should be no possible source of ignition. Workers should not be permitted to carry matches or lighters into the work area. Shoes with steel nails or tips should be prohibited and all tools should be of non-sparking design. Automotive vehicles should be restricted from entering the area.

4.11.3 Vapor Freeing the Tank

Each tank to be cleaned should be freed of flammable vapors before work is undertaken within the tank. This entails replacing all vapors within the tank with fresh air. This can be undertaken with educators, fans, and blowers designed for use in explosive atmospheres. The American Petroleum Institute advises that testing for entry be undertaken in the following manner:

. . ."To determine the progress of vapor-freeing operations, the atmosphere in the tank and the surrounding area should be tested frequently throughout the operation with a vapor indicator. . ."

. . ."The tester should be thoroughly familiar with the reading and handling of the instrument. Before taking readings, he should determine that the instrument is in proper working condition and correctly calibrated. It is important that he adhere to the manufacturer's recommendations for checking and calibrating the instrument. . ."

. . ."When vapor concentration has been reduced to 50 percent of the lower flammable limit and air is entering the shell manways, the presence of personnel around the tank no longer need be restricted. However, introduction of potential ignition sources within the area should still be subject to rigorous control based on the vapor concentration tests, wind direction and velocity, and other factors.

When vapor concentration in the mixture leaving the tank is reduced to approximately 20 percent of the lower flammable limit, the first objective (removal of the flammable atmosphere) has been essentially accomplished. However, this condition is not necessarily permanent, and ventilation and vapor testing should be continued. The exact vapor concentration which will be considered safe before proceeding with the next step in the work will depend upon the program set up for sludge removal. This, in turn, will depend on the size of the tank, the facilities available, theamount of sludge and other factors.

If it has been determined that other toxic substances are not present at levels above TLV, the tank has not contained leaded gasoline since the previous cleaning, the vapor indicator registers a reading not exceeding 20 percent of the lower flammable limit, and oxygen content is at least 19.5 percent, the tester may enter the tank without respiratory equipment to make further tests at various points inside the tank. In most every instance if TLV requirements are met, the LFL* will be well below 20 percent of the LFL. For large diameter tanks it is advisable for the gas tester to wear respiratory equipment for entry even though all of the above requirements have been met. During this testing, ventilation should be continued. For higher concentrations, anyone entering the tank should wear respiratory equipment which provides an independent supply of air in sufficient quantity to produce a positive pressure in the full-facepiece throughout the breathing cycle. Preferably no work should be started within the tank until it is vapor-free. . ."

4.11.4 Sludge Removal and Disposal

Initial tank cleaning is normally undertaken using a high pressure water hose through the access openings. The sludge and residues are directed to either the water draw or a pump out connection in this manner. Ventilation of the tank should be continued during the hose cleaning process since vapors can be generated and released during this cleaning action. The

---

*Lower Flammable Limit

disposal of residue mixture warrants strict supervision and ignition sources should be avoided at all times. API advises retention in a guarded sump and should the discharge be directed into an open pit or retention pond, all ignition sources should be eliminated. Discharge into a public sewer system should be avoided at all times due to the hazards involved.

Final cleaning is largely a manual effort whereby the sludge water and scale mixture is brushed into piles and removed in either buckets or wheelbarrows.

API Publication 2015 Second Edition, November 1976, provides considerable detail on personal safety, gas freeing, monitoring, and cleaning of the tank. Unfortunately, it does not describe how to dispose of the sludge removed from the tank. In the past this ultimate disposal was gained by burying the waste within the confines of the diked retention area. In lieu of the hazards developed by the buried material, some organizations placed a dated burial cross in the center of the burial site to warn against conducting any excavation in the area. This was the extent of precautions taken and the area was considered safe after a few years of burial. This procedure is no longer acceptable since the product contained in the sludge can quickly leach down to ground water and cause contamination. A more environmentally safe method of disposal is demanded.

The US/EPA suggests* the following actions as being appropriate for a waste handling strategy.

---

*Federal Register, Vol. 41, No. 161, pp. 35050-1.

1. Minimize the quantity of waste generated by modifying the industrial process involved.

2. Concentrate the waste at the source (using evaporation, precipitation, etc.) to reduce handling and transport costs.

3. If possible, transfer the waste "as is", without reprocessing, to another facility that can use it as a feedstock.

4. When a transfer "as is" is not possible, reprocess the waste for material recovery.

5. When material recovery is not possible,

   a. Incinerate the waste for energy recovery and for destruction of hazardous components, or,

   b. If the waste cannot be incinerated, detoxify and neutralize it through chemical treatment.

6. Use carefully controlled land disposal only for what remains.

<u>References</u>:

1. "Cleaning Petroleum Storage Tanks". API Publications 2015, Second Edition, November 1976.

2. "Waste Clearinghouses and Exchanges: A Summary. New Ways for Identifying and Transferring Reusable Industrial Process Waste. EPA Report SW-130c.1 A summary of report SW-130c.

4.12 Buried and Partially Buried Tanks

4.12.1 General

Although fire codes and regulations specify that certain materials be stored in buried tanks as far as practical, their use should be kept to a required minimum. An unseen tank can deteriorate when placed in contact with water or moist soil and it is reasonable to consider that the buried tank can lay in moist soil for at least 50 percent of its' operating life. Under this condition, the metal of the tank is exposed to a force that demands release. The force causes the metal to actually dissolve into the sourrounding soil or water, after which it usually combines with oxygen to form oxides. This is the act of metal returning to its natural state.

The corrosion is a continuous electrochemical process that results in metal destruction. Underground corrosion of metal surfaces is a direct result of an electric current caused by the reaction between the metal surfaces and chemicals that exist in the soil or the water. The flow of current from one portion of the metal to another part of the structure, through the surrounding soil or water, causes metal ions or particles to leave the surface of the metal and causes pits. This eventually causes complete destruction of the metal. The rate of current flow determines the life span of the metal. One ampere of current discharge from iron can remove 22 pounds of metal in one year. Harco Corporation has developed cumulative leak curves that indicate that after several years of trouble-free operation, leakage is possible between the fifth and sixth year of unprotected burial. Leakage is then a positive indication of increasing future trouble as three additional leaks can be anticipated in the next year.

With the increasing cost of material and labor for tank burial and removal, the provision of cathodic protection becomes cost beneficial if installed at the time of tank burial. Figure 4-40 depicts a typical buried tank cathodic protection system and placement of protective annodes and D.C. rectifier. Section 7.3.2, External Corrosion, provides additional details on cathodic protection.

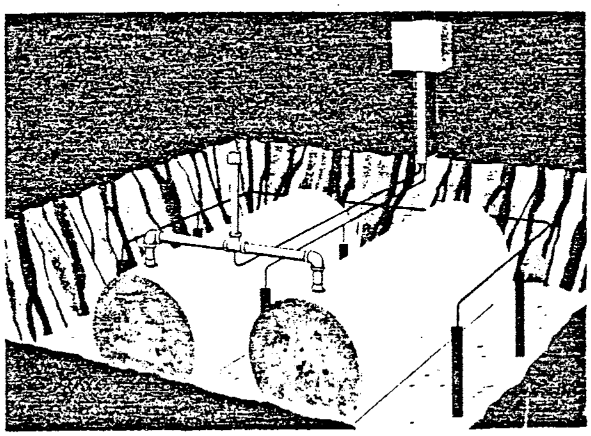


FIGURE 4-40.

Galvanic Protection of Buried Tanks (Illustration Courtesy Harco Corp., Medina, Ohio)

4.12.2 Protective Coatings and Wrappings

In addition to cathodic protection, buried tanks should be abrasive blast cleaned and coated with a protective coating before burial. Basically the principles of protecting a buried tank duplicates those for protecting buried pipeline. A variety of protective coatings are available. They include coal tar, somastic, and polyethyne tape.

The Tapecoat Company, Evanston, Illinois has specialized in hot applied coal tar coatings, cold applied tape coatings, and mastic coal tar coatings which can be spray applied to a tank. Figure 4-41 shows a mastic coal tar coating being applied prior to tank burial.

4.12.3 Hydrostatic Testing

As with pipelines buried tanks should be subjected to hydrostatic testing. Piping arrangements should be available to isolate the tank for hydrostatic testing purposes. A five year testing frequency is advisable using a water test pressure not over 1 1/2 times maximum working pressures. Time permitting, the pressure should be maintained for a period of an hour or more using a test pressure gage to detect any pressure loss during the test period. The water used to fill and pressure test the tank should be room temperature, but not below 70°F and if desired, a dye can be mixed with the water. Should a leak occur, the dye in the water will more readily aid in detecting the approximate location of the leak in the tank.

4.12.4 Partially Buried Tanks

Tanks partially buried in or resting directly on the earth should be avoided. Metal deterioration is rapid due to obvious reasons and the deterioration cannot be detected until failure

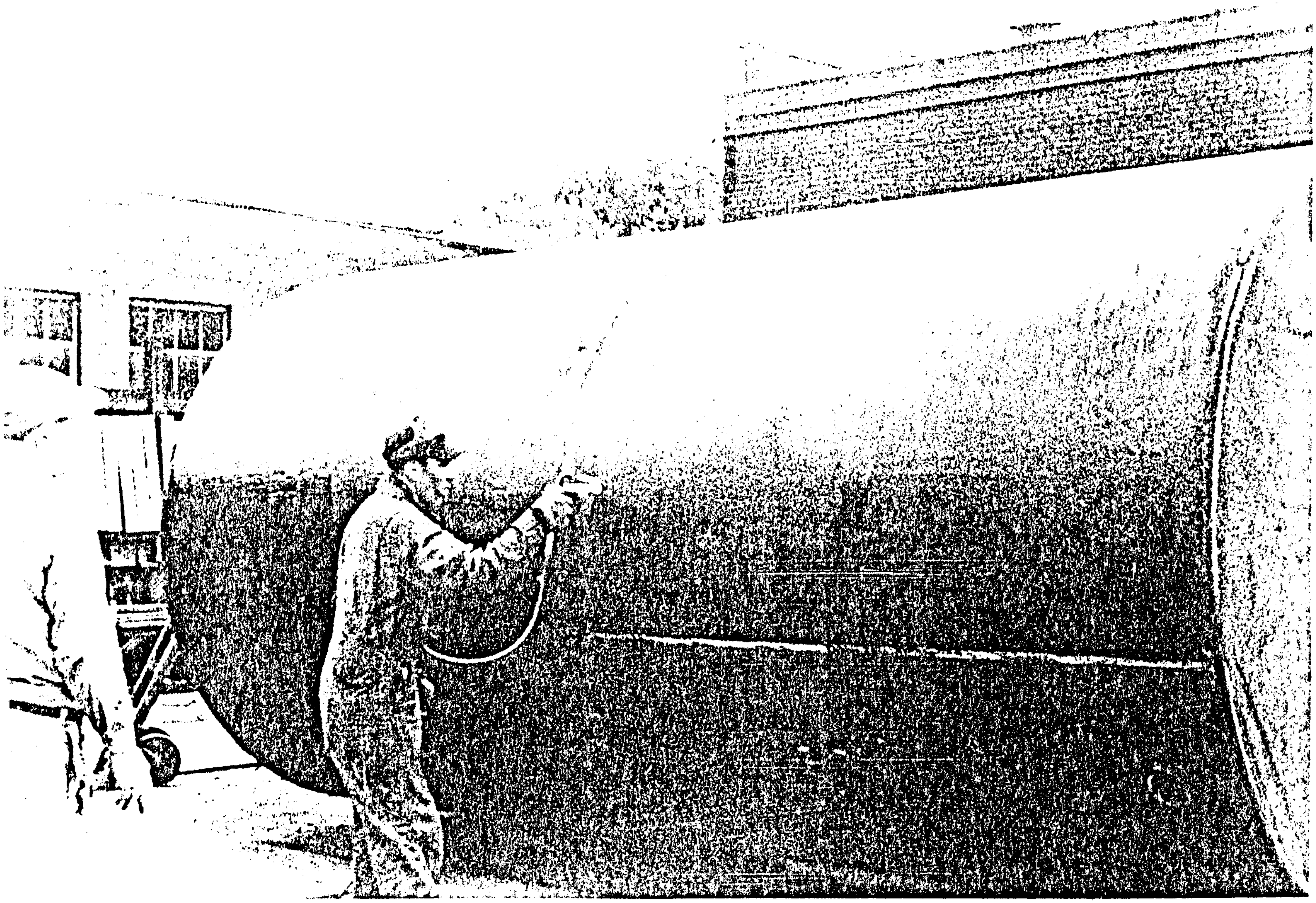


FIGURE 4-41. Applying Mastic Coal Tar Coating Using Spray Technique
(Photograh Courtesy The Tapecoat Company)

occurs. Tanks should be raised above the surrounding earth and be supported by adequately designed support structures installed on a sound foundation. There is literally no benefit from partially burying or supporting a tank directly on the earth other than eliminating the cost of properly engineered supports. This cost saving is quickly eliminated from the rapid deterioration of the tank metal and short life span of the vessel.

5. ELECTRICAL TRANSFORMER DIELECTRIC SPILL CONTROL

5.1 General

This report section deals with the prevention of spills of cooling liquids from electrical transformers and capacitor banks. Large transformer banks can contain $\pm$250 gallons per phase and the dielectric can be either mineral oil or polychlorinated biphenyl (PCB). This material is on the US/EPA Toxic Chemicals List. A typical PCB insulation coolant mixture could be 70 percent PCB (AROCLOR 1254) and 30 percent trichlorobenzene. Federal investigations* have revealed that PCB's released into a waterbody pose an unacceptable risk to the health of man and the environment.** Even though the acute toxicity of PCB's is not too severe their extreme persistency and bioaccumulation in the environment make spills of PCB's of particular significance and cleanup actions have been costly.

Normally PCB's used as dielectrics in transformers and large capacitor have a life equal to that of the equipment, and with proper design leakage does not occur. When the equipment is scrapped the quantity of dielectric normally justifies regeneration.

---

*EPA Federal Water Pollution Control Act as Amended particularly those portions that deal with water quality criteria and standards, effluent standards, and spill prevention.

**EPA Toxic Substance Control Act; EPA Resource Conservation and Recovery Act; OSHA, HEW/NIOSH and FDA.

Askarel is the generic name given to PCB used in electrical equipment. Each electrical manufacturer has given a trade name to the particular grade of askarel used in its products. Pyranol, Inerteen, NoFlamol, and Saf-T-Kuhl are among the better known trade names.

Askarel has a specific gravity of 1.4 to 1.5 depending on its particular formulation. When it is spilled on land, it rapidly permeates the soil, finding its way to a water table; when it is spilled on water, it sinks to the bottom and remains there to be ingested by all forms of aquatic life to start the accumulation in the food chain.

5.2 Spill Containment

At most installations, should a transformer or a capacitor casing fail, the PCB content would flow to the nearest storm drain, then to a drainage ditch and ultimately to a waterbody. Oil retention sumps in storm sewer lines have little value in containing PCB's since they do not fall into the category of a floatable material.

To contain a spill transformers and capacitor banks should be enclosed within poured concrete, curbs, or walls. The wall need not be high as long as its configuration will contain the dielectric content of the largest transformer within the enclosure. With capacitor banks, consideration should be given to "flashover" where more than one capacitor could be damaged by the failure of one unit. The enclosure should be equipped with a floor drain that can be filled with Dow Imbiber Beads (see Section 4-8, Tank Draining). With this type of drainage system, it is possible to leave the drain valve from the restrained area open to drain away rainwater. Should PCB's make contact with the system, the beads will absorb the PCB's and swell up to 27 times their original volume in the process. This absorbtion is in the nature of the chemical rather than a physical process since the absorbed fluids cannot be squeezed from the beads, even if the bead is cut with a knife. The beads are unaffected by water which can flow through the floor drain. They will, however, absorb the contaminating fluid from the water. They are of special value in containing askarel since the pollution problem is removed from the environment once the askarel has been imbibed. Following a spill, the contained material and the askarel saturated beads can be shipped to a US/EPA authorized PCB disposal facility.

Table 5-1 provides source data for the sorbent materials.

Figure 5-1, as provided by Dow Chemical U.S.A., details the construction of a typical retention and drainage system.

This section is not intended as an endorsement of a single manufacturer's product; Dow is the only known manufacturer of the imbiber beads.

TABLE 5-1.

IMBIBER BEAD PRODUCT DISTRIBUTORS

MANUFACTURER AND TRADE NAME	TECHNICAL DETAILS	
Dow Chemical U.S.A. Midland, MI 48640 Imbiber Systems Functional Products & Systems 2020 Dow Center	DESCRIPTION:	- cross-linked solid organic polymer with imbibitive (true absorbent) properties for most organic fluids. Composition is mainly tertiary-alkyl styrenes with other monomers to imbibe (or absorb) organic solvents without dissolving.
U.S.A. DISTRIBUTORS Callahan Chemical Co. Box 53 Palmyra, N.J. 08057 (609-665-6640)	SPECIFICATIONS:	beads average 150 or 350 microns in diameter - specific gravity 0.96-0.97 - absorb (or imbibe) up to 27 times its own weight (depends on solvent and its viscosity). - bulk density of imbiber beads ~38 lbs/cu ft (626 kg/cu M)
Illinois Chemical Co. Box E Highland Park, IL 60035 (312-433-1145)	PRODUCTS:	- Imbiber Beads - Soil Sealing (drainage devices) - Packets and Blankets (spill control) - Valves and Cartridges (water drainage) - Drainage Devices for diked areas - Shipping Containers (safety) - Disposal of hazardous and nuclear contaminated oils to prevent liquid flow
R. G. Metz Co. 3914 Miami Road Cincinnati, OH 44227 (513-271-2468) Licensed for use in The State of California for "Oil Spill Cleanup"	PACKAGING:	- Imbiber Beads 40# (18.2 kg)/fiber drum - Imbiber Packets (17.5 cm x 17.5 cm) 100/box - Small Blankets (35 cm x 53 cm) 15/box - Large Blankets (53 cm x 106 cm) 5/box - Imbiber Valve (8.89 cm diameter x 11.43 cm long) 12/box - Imbiber Cartridge (15.24 cm diameter x 7.62 cm high) 4/box - Imbiber Shipper Kit 1/2 liter 6/box - Imbiber Shipper Kit 1 liter 4/box

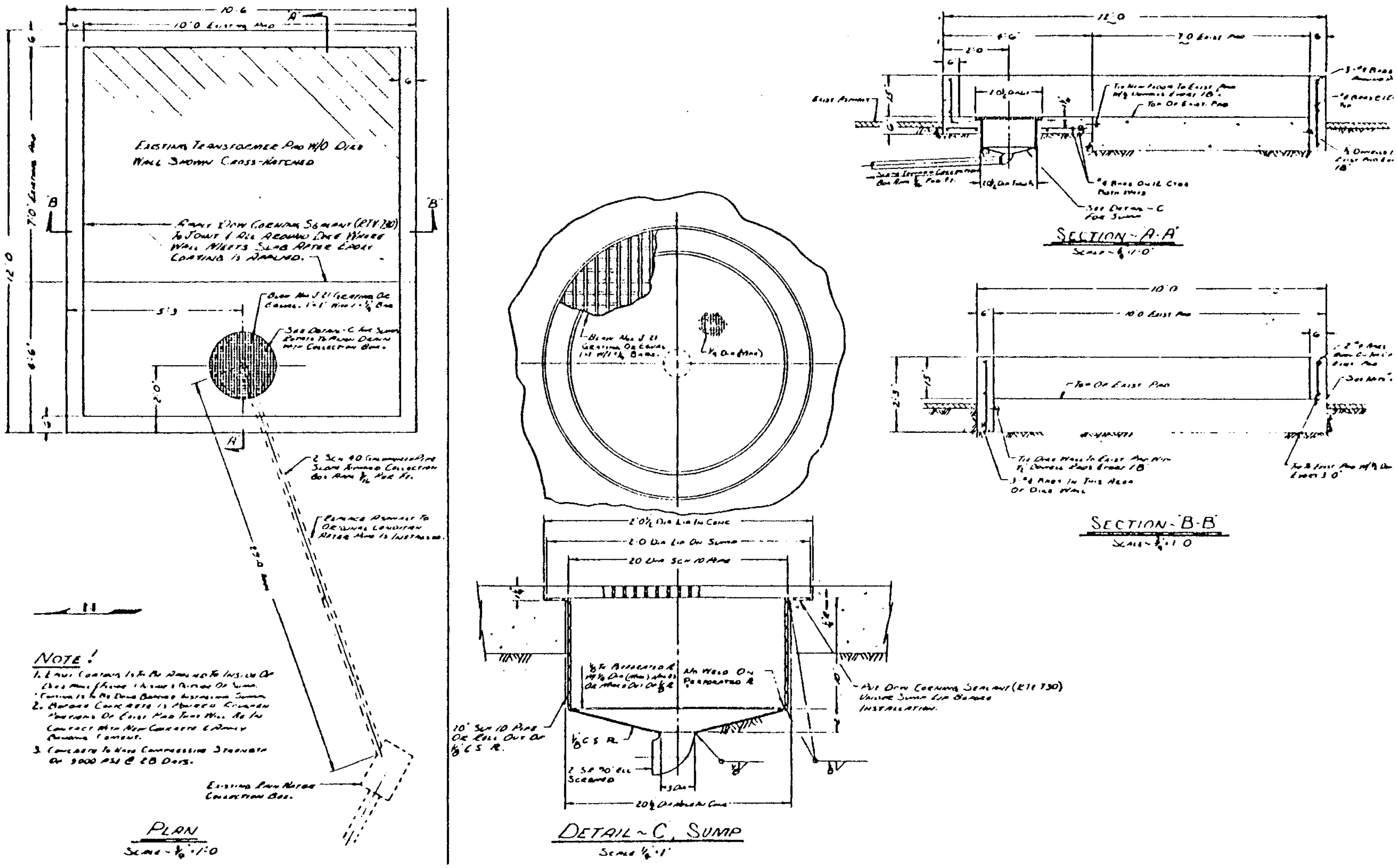


FIGURE 5-1.

Typical Spill Restraining and Imbiber Bead Drainage System (Illustration : The Dow Chemical Co., Midland, MI)

6. INPLANT PIPELINES

6.1 General

Inplant pipelines are a major source of spillage. At many plants, lines have been buried as long as 30 years. This was a time when coatings were not as good as they are today and the use of cathodic protection was rarely used. This deficiency is very predominent in the Northern states. However, the Southern states, especially in the Gulf Coast area, have been more prone to provide cathodic protection. The first sign of leakage generally occurs when product comes bubbling up to the grade surface. In many cases leakage could continue for many months before detection and line replacement. Very few facilities expose and examine pipe sections and it is even less customary for hydrostatic testing of lines to be conducted.

There has developed a noticeable trend, however, to install new lines above ground and in some cases to raise lines up out of burial trenches. Hydrostatic testing of lines, when conducted, should be at 1 1/2 times the lines' maximum designed working pressures.

6.2 Color Coding of Lines

There has been no definite trend toward color coding or the labeling of lines to indicate the product contained therein or pumped through the line. The advantage of color coding and labeling warrants the expense involved since human error in opening the wrong valve is greatly reduced once workers have become indoctrinated to the color code.

Color coding presently varies by plant. There has been no leadership in assigning a certain color to a certain oil product.

6.3 Overhead Lines

The height of inplant lines is an important factor. Spills have been experienced when a visiting truck tore down a bridge of lines passing over a plant roadway. Overhead lines should be positioned at heights well above that of any motor vehicle and plant security should be alerted to gain height information on visiting vehicles should they give an indication of excessive height (vehicle or load). The maximum height of pipelines should be posted at the entrance security office.

6.4 Pipeline Supports

Until recent years, inplant pipeline supports were rarely an engineered item. During the course of nationwide surveys a wide variety of support structure has been viewed and critiqued. One New Jersey facility was satisfied to support a 6 inch diameter line with a piece of 2 inch x 4 inch scantling wood and an empty grease can. At other locations dock line are frequently supported by sections of creosoted lumber of railroad tie dimension. Much to their remiss a Massachusetts' plant experienced a major spill from this practice. The creosote had dried out of the wood until it retained rainwater which in turn corroded the underside of the pipeline. The corrosion with a combination of abrasion caused by the pulsating action of the line during a pumping period literally ate away a section of the pipe equal in dimension to a man's hand. During an after dark offload action, the leak went undetected for an undetermined period of time. The entire harbor, however, was covered by a fairly thick oil slick. The basic steps to prevent pipeline leakage can be listed as follows.

- Using nondestructive, ultrasonic testing techniques, make at least an annual check of pipeline thickness to determine the extent of internal corrosion. Comparative records should be made and retained to gage the rate of internal deterioration and to estimate the line's anticipated lifespan.
- On a suggested three year basis, partially rotate the lines to extend the life of the line from support contact wear and rainfall exposure of the upper half of the pipe.
- Provide supports that make a minimum of physical contact with the pipe metal. Rubber roller type supports are suggested since they rotate with

the pulsing action of the pipe, are resilient, and do not interfere with thermal expansion and contraction of the pipe. The dimension and strength of the internal spindle in the roller should be adequate to support the full load of the pipe section it support. Cast iron should not be used except for roller bases, rollers,* or anchor bases, etc. under mainly compression loading.

- Maintain a good protective coating on the lines at all times.

- On at least a five year basis subject the lines and attached fittings to a hydrostatic test at a pressure 1 1/2 x maximum designed working pressure for the system. This pressure should be maintained for at least 24 hours. Hydrostatic testing of new or modified lines is mandatory under Federal law.

o Whenever practical "dry" lines should be maintained. This is possible by clearing the lines of contained product by the injection of an inert gas into the line. This action is generally conducted from the plant's loading/unloading dock to

---

*Some facilities provide "V" type support spools that are of rotational design.

clear the entire length of the line back into the storage container.

6.5 Valves

All valves should naturally be designed to meet the pressure demands of the entire pipeline system. Valves should also be compatible with the pipe or fittings to which they are attached and the liquid they transport.

Unfortunately, few plants have been found that have developed a safety and/or security practice of locking valves in the closed position when not in active service. It is most important that master flow control valves be locked-closed to avoid unauthorized tampering or accidental opening of the wrong valve. The time delay to unlock valves will give the attendant time to clearly think over what he is doing. Basically, the opening and closing of pipeline valves should not be a rapid operation. Sudden opening of a valve can "shock" the downstream section of the line unless prepared in readiness for the liquid flow. On this basis time spent to unlock and lock a valve can be time well spent.

Locking devices can consist of an intertwined chain and a padlock. However, most valves secured in this manner can be "cracked" open enough to gain liquid flow. A more secure method is to hinge finger pieces to the valve body, which, when raised, encircle either the outer rim of the valve wheel or one of the valve wheel spokes. A padlock is then used for positive closure.

A comparatively new method for detecting leakage of acids and caustics as handled in a refinery can be gained by lacing covers over the valves or over the flange couplings. (Figure 6-1). The covers are a standard color but the color changes upon contact with a leaking product. The color change is so striking that it can be immediately perceived by a passing worker or an aerial survey team. The manufacturer of these products, Slickbar, Inc., Southport, Connecticut can provide samples of the material for testing with any product to determine the extent of color change that can be expected. Table 6-1 defines the reaction of the covers to a variety of materials. Figure 6-2 illustrates a flange cover distributed by Slickbar, Inc.

6.6 One-Way Flow Check Valves

The use of one-way flow check valves can provide a high degree of protection against valve failure and product backflow. The installation of check valves on fill lines that travel to a storage tank are exceptionally important if the line connects into the bottom of the tank. Without a check valve the unintentional opening of a valve can drain the content of a line and should the master flow control valve at the tank be open, considerable backflow can be anticipated.

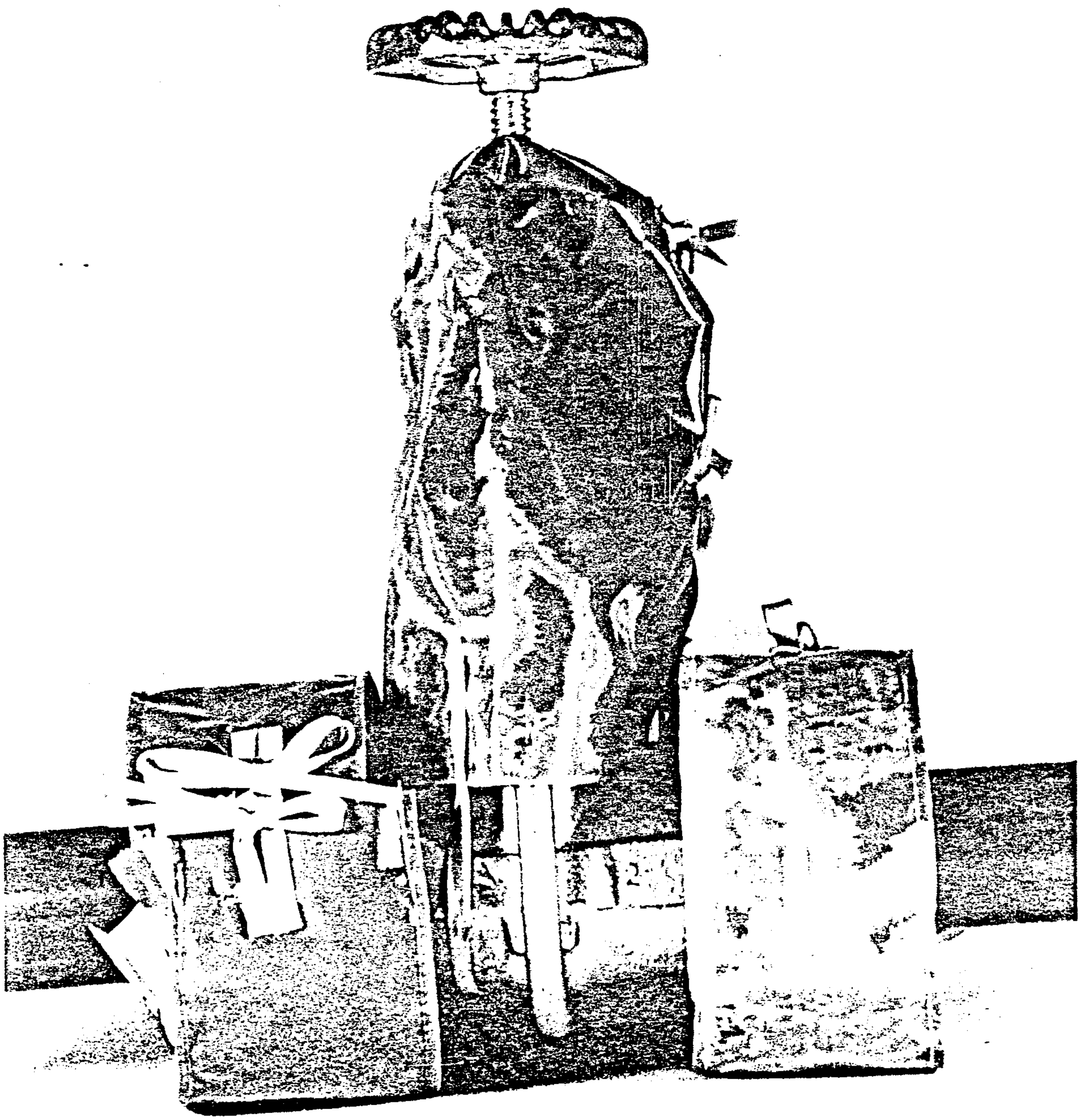


FIGURE 6-1. Color Changing Valve Cover
(Illustration Courtesy Slickbar, Inc.)

MILSHEFF SPRAY-STOP

VALVE & FLANGE COVERS

INDICATING COVER REACTION LIST

Indicating type covers will change color in those areas in contact with "triggering" reagents. Below is a list of some reagents and their effect on the covers. The color change occurs on the inside of the cover but will make a mark on the outside. Reagent concentration will affect the time and color change. The color of the untriggered cover is international orange. For those reagents not listed we will be pleased to furnish a sample of indicating material for your test and evaluation.

TYPE REAGENT	CONCENTRATE	REACTION/COLOR/TIME	OUTSIDE MARK
Acetic	100	None	None
Adipic	1.4	None	None
Ammonia	28.	None	None
Calc. Chloride		None	None
Chromic	50	None	None
Chromic	25	None	None
Ferric Chloride	70	Bleached Gray	Slightly Dark
Ferric Chloride	25	None	None
Formaldehyde	40	None	None
Hydrobromic	48	Bright Yellow Immediately	Bright Yellow
Hydrochloric	38	Bright Yellow - 5 min. To White	Colorless Area
Hydrofluric	100	None	None
Hydrofluric	50	Yellow - 10 min.	Slight Stain
Hydrofluric	25	Yellow - 10 min.	Slight Stain
Hydrofluric	15	Slight Yellow - 10 min.	Slight Stain
Hydrofluric	10	White Salty Deposit	None
Nitric	70	Color Removed - 5 min. White	Color Removed
Nitric	30	Brilliant Yellow 2 or 3 minutes	Brilliant Yellow
Nitric	20	Brilliant Yellow 2 or 3 minutes	Brilliant Yellow
Nitric	5	Slight Oil Mark	Slight Oil Stain
Oleic	100	Oily Mark	Oily Mark
Oxalic	51	Pink Stain - 20 min.	Pink Stain
Perchloroethylene	100	Oily Mark	Oily Mark
Phenol	5	Oily Mark	Oily Mark
Phosphoric	85	Dark Yellow 3 min.	Dark Yellow
Silver Nitrate	50	Black 15 min.	Dark Stain
Sodium Bichromate	50	Dark Stain - 3 min.	Dark Stain
Sodium Hydroxide	50	Light Yellow - 3 min.	Light Yellow
Sodium Hydroxide	35	Light Yellow Immed.	Light Yellow
Sulphuric	96	Dark Yellow - 25 min.	Med. Yellow
Sulphuric	70	Light Yellow - 15 min.	Light Yellow
Sulphuric	30	Light Yellow - 5 min.	Light Yellow
Sulphuric	10	Light Yellow - 3 min.	Light Yellow
Sulphuric	5	Light Yellow Immed.	Almost White
Hydrogen peroxide		None	None
Carbon tetrachloride		None	None

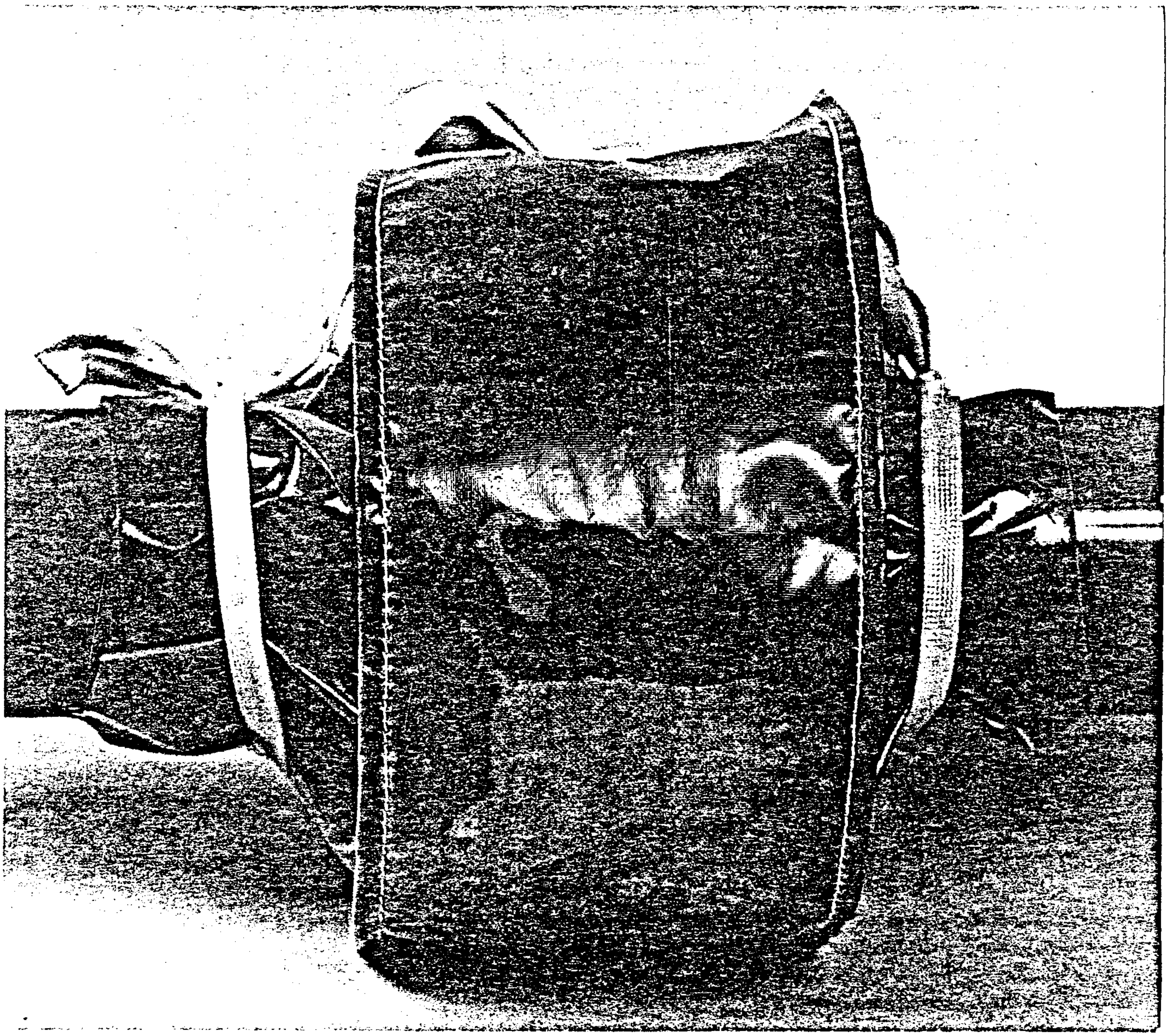


FIGURE 6-2. Drip Control Cover
(Illustration Courtesy Slickbar, Inc.)

For this reason fill lines should have a one-way flow check valve positioned at the termination of the line immediately adjacent to the master flow valve on the receiving end of the pipe. Although not a common practice, a check valve installed on the line between the tank and the tank's flow control valve can provide an added degree of safety. The position of the failsafe check valve at the base of the tank provides a high degree of protection against line valve

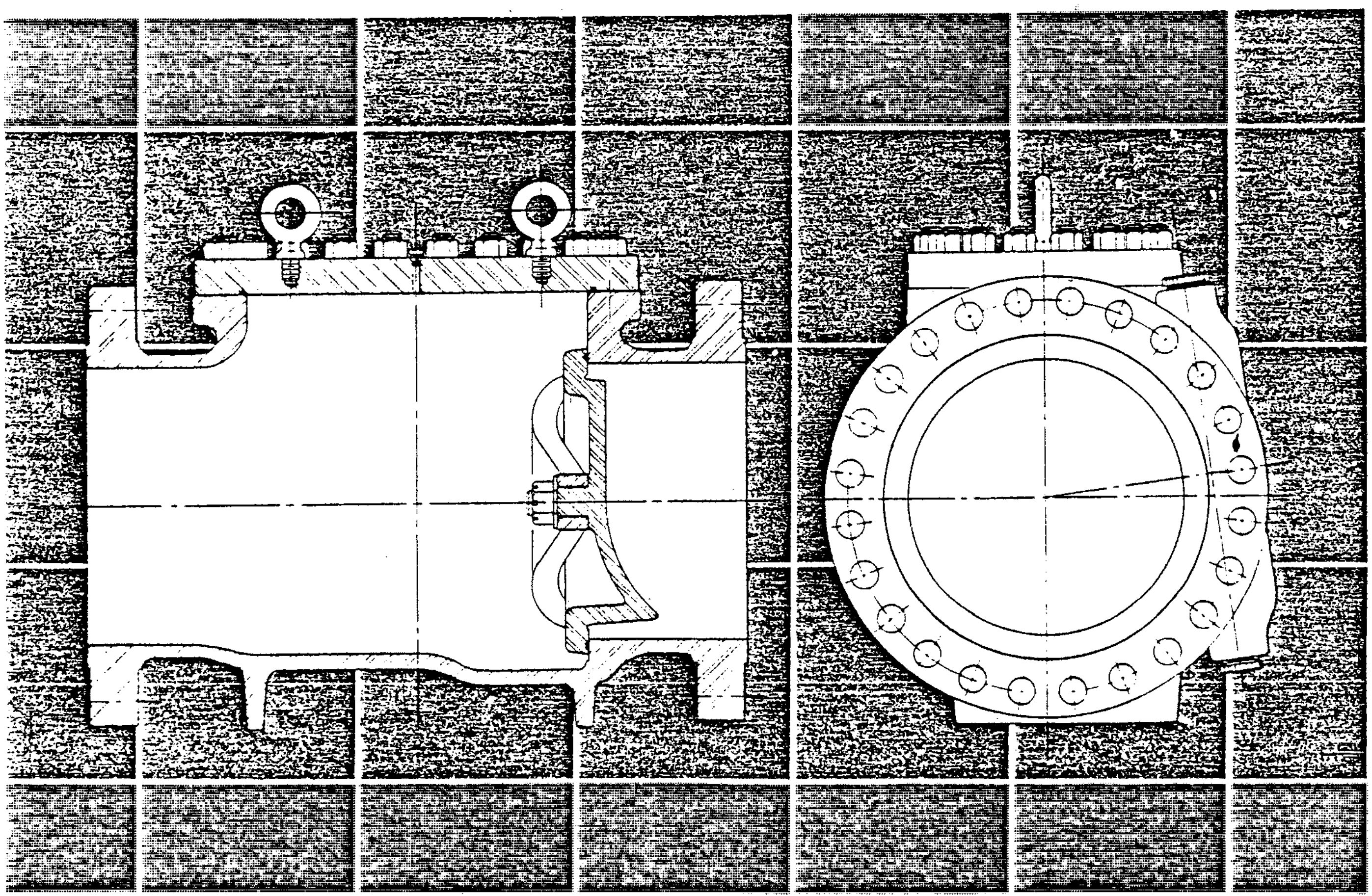


FIGURE 6-3.

Check Valve Configuration
(Illustration Courtesy Wheatley/
Geosource Inc.)

failure. Unfortunately dual purpose lines used both for fill and discharge purposes cannot be protected in this manner, although a number of designs now incorporate two lines--a fill and a suction. Fill lines that are positioned into the tank above the liquid level do not require check valves unless provided as protection against backflow of the product remaining in the fill line (Figure 6-3).

One manufacturer, Wheatley/Geosource, Inc., Tulsa, OK produces a wafer check valve that provides a compact, lightweight, and inexpensive means to control backflow in close-quarter applications. They are available in carbon steel and 316 stainless steel in two basic designs. Sizes 2 inches through 12 inches are furnished with either a drop-in clapper or a through-pin clapper. Sizes 14 through 48 inches are constructed with a through-pin clapper.

The valve's materials of construction, face-to-face dimensions, and performance conform to API-6D and the API monogram can be applied upon request. The clapper seat o-ring is located in the valve body to eliminate washout. Nitrile rubber is standard with fluorocarbon and butyl rubber and Viton A as optional; the latter material being the best suited for hydrocarbon products. Optional body facings (serrated, ring joint, or plain face smooth) are also available. Working pressures range from 275 to 3600 psi. The valves can be readily inserted between two flanges if the line has play enough to be crowbar separated. Once installed, a bubble-tight closure is claimed by the manufacturer.

The major change involves the replacement of the flange bolts to accommodate the wafer check valve. A two inch diameter valve is 3/4 in. wide and costs in the vicinity of $90. A 12 inch valve varies between 1 1/2 inches to 2 inches in width and costs between $470 and $700 depending on the working pressure requirement (Figure 6-4).

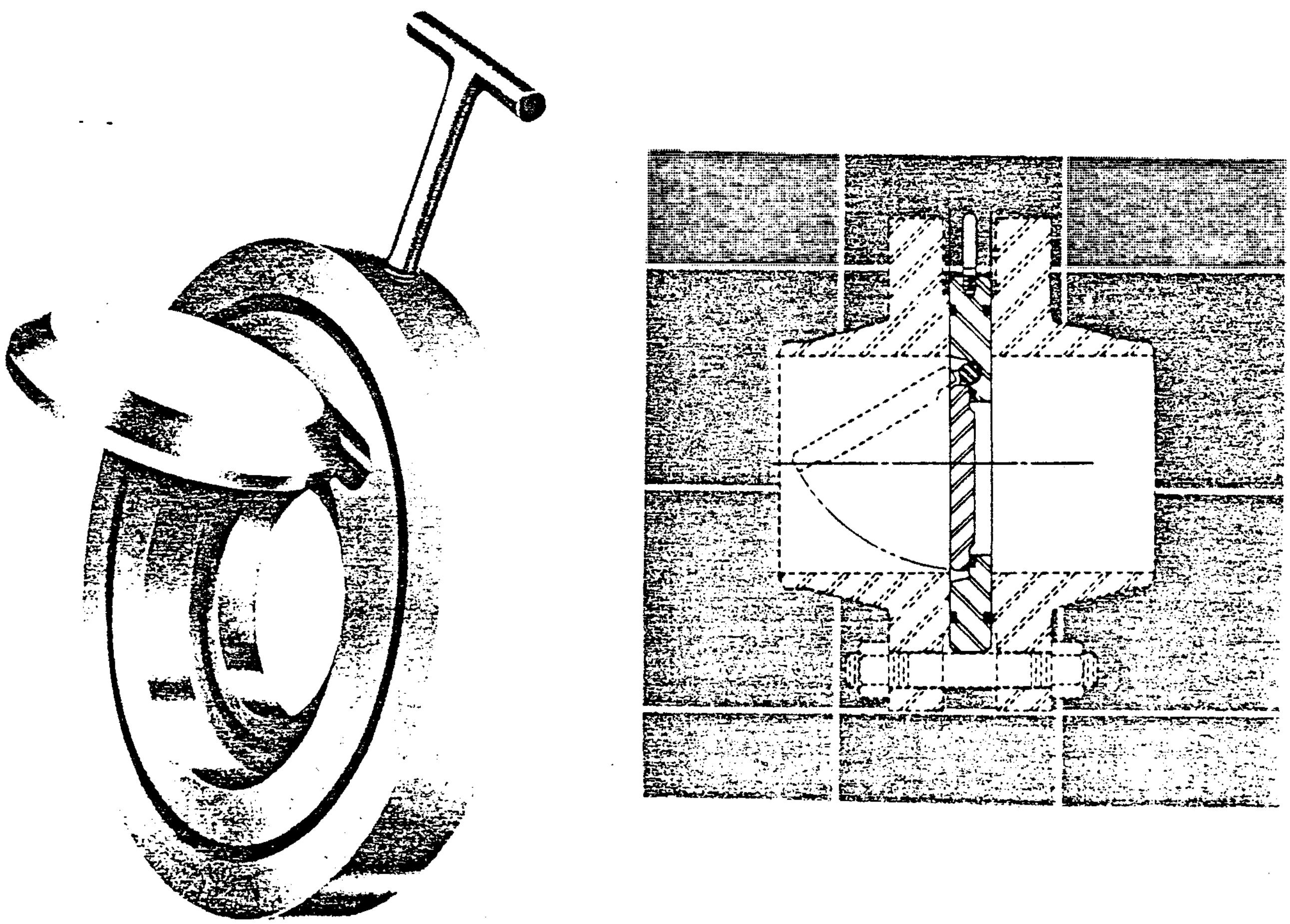


FIGURE 6-4. Wafer Check Valve and Method of Installation
(Illustration Courtesy Wheatley/Geosource, Inc.)

6.7 Stemming a Pipeline Leak

One of the simplest methods for reducing and possible fully containing a leak in a line is to drive a number of soft wooden plugs into the rupture or corroded opening. A good maintenance crew should have wooden plugs available for such an emergency (Figure 6-5).

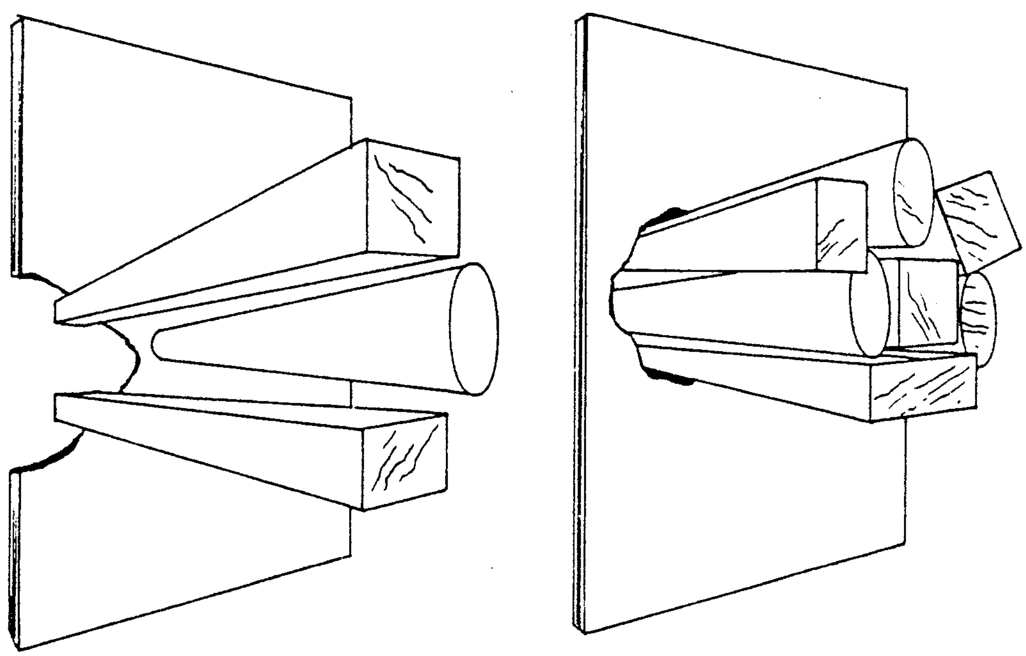


FIGURE 6-5. Plugging a Leak With Wedges

Note: Although a flat surface is depicted the technique can also be used on pipelines. (Illustration Courtesy U.S. Navy Damage Control)

Another remedy is to have available within the plant a range of clamps that can be used to encircle the defective line and be tightened into position. The range of pipe diameters of inplant pipelines is normally not too excessive and clamps of varying length and diameter can be stored as a response measure. This is, however, a technique generally ignored by plant personnel. In 34 years of plant surveying by one of the authors this leak containment technique has never been viewed.

7. TRANSPORTATION PIPELINES

7.1 General

The transportation of oil in overland pipelines is expanding annually. Some typical statistics on existing lines is contained in the following table (Table 7-1).

TABLE 7-1

Some Typical U.S. Pipeline Installations

Products Line	System Mileage	System Pipe Diameters, in.	Capacity, b/d	Pump Stations	Installed Horsepower	Delivery Terminals	Tankage Capacity, bbl
Colonial Pipeline Co.	2845	6 to 36	800,000	27	296,250	164	18,819,000
Great Lakes Pipe Line Co.	6228	4 to 12		53	101,515	41	13,242,200
Buckeye Pipe Line Co.	2670	6 to 16	629,000	34	49,580	51	3,155,300
Plantation Pipe Line Co.	3213	4 to 18	354,000	39	121,230	169	5,829,400
Texas Eastern Transmission Corp., Little Big Inch Div.	3222	4 to 20	334,000	59	76,830	16	20,976,600 (includes underground storage)
Magnolia Pipe Line Co.	3225	4 to 12	319,000	34	19,300	49	925,000
American Oil Co.	2360	3 to 12		28	27,075	27	
Southern Pacific Pipe Lines	1923	3 to 16	217,000	19	22,365	18	4,836,791
Laurel Pipe Line Co.	447	10 to 24	200,000	4	12,800	22	3,555,440
Atlantic Pipe Line Co.	983	4 to 14	138,000	10	12,500	56	465,000
Phillips Pipe Line Co.	2633	6 to 12	122,000	28	58,675	9	7,713,450
Mid-America Pipeline Co.	2538	4 to 10	107,000	27	39,700		2,582,000
Dixie Pipeline Co.	1090	6 to 12	75,000	14	14,550	7	47,000
Continental Pipe Line Co.	746.46	4 to 8	71,900	9	5,365	10	297,000
Salt Lake Pipe Line Co.	1483	6 to 8	70,700	10	12,500	14	684,000
Cherokee Pipe Line Co.	1481	3 to 36	60,000	11	10,600	11	2,358,900
Champlin Petroleum Co.	710	2 to 6	54,600	9	3,725	7	1,095,742
Koneb Pipe Line Co.	693	6 to 10	50,000	13	6,850	6	1,604,220
Yellowstone Pipe Line Co.	744	3 to 10	40,180	5	5,200	14	106,000
Gulf Refining Co.	474	8 to 12	18,000	3	930	4	801,500
Okan Pipeline Co.	447	3 to 6	14,600	2	2,860	5	

From: Colonial Pipeline Co.

Transportation rates have reached 1,584,000 barrels per day. Probably one of the greatest pipeline construction projects completed within the last decade is the Alaskan pipeline. This line built and operated in a very hostile environment transports crude oil from oil producing wells on the Alaskan North Slope 800 miles to an ice-free deepwater loading terminal in Valdez, Alaska. The line crosses three mountain ranges, 800 streams and miles of permafrost on its journey south to Valdez. It is a unique engineering feat and the largest privately funded construction project in history.

The oil industries have calculated that for overland movement, pipelines provide the least expensive transportation medium. This to the extent that is costs 15 cents to send a one ounce letter from Houston to New York; but a gallon of gasoline travels the same route by pipeline for less than 1 1/2 cents. Excluding utility gas distribution lines, there are presently some 550,000 miles of land and sea lines in the United States, transporting 7 billion barrels of oil and 20 trillion cubic feet of gas annually.* The low transportation cost has to a large degree curtailed the need for marine terminals and reduced the quantity of refined products transported by coastal tankers. It has been found more economical to locate a marketing terminal on a stub line from an overland main line. By this action it is possible to maintain full tanks of product without the need to locate on a navigable waterway which under any circumstance can be categorized as a potential trouble spot.

7.2 Pipeline Safety

Modern pipelines have been vastly improved over those constructed not many years ago. This resulted from advanced

---

*"Energy Lifelines Under The Sea." API Publication.

technologies, improved materials and welding techniques, more accurate testing procedures, computer programming, the advent of versatile pipelaying equipment, and remotely actuated and automated flow control systems. A small staff of people located at remote control centers, assisted by technicians and maintenance personnel, can keep an entire pipeline system running and maintain a continuous stream of oil or gas from source to destination.

They are, however, supported by sophisticated equipment--measuring and monitoring devices, computers, controls, telecommunication and other safety systems.

Turbine metering systems are available to provide a flexible means for reliable and accurate measurement of oil transported through pipelines. Digital telemetering of all controls, indications and data between two stations permits accurate, rapid comparison with flow measurements at a receiving terminal. The comparison technique permits continuous leak detection monitoring and immediate remote shutdown of any or all pipelines.

It is possible to provide safety shutdowns and/or alarm devices for parameters such as flow, liquid level, temperature, pressure, overspeed, and vibration. The accuracy of available systems is in the vicinity of +1.0 percent of total line flow. If the pumping stations flow rate should be greater than that of the receiving terminal by more than 1 percent, an alarm can be actuated indicating a possible loss of oil. Normally two alarms within a period of five minutes result in a shutdown of the pipeline system.

An alternate or additional monitoring system consists of flow-pressure relationship testing. Should a decrease in discharge pressure and an increase in flow rate occur at the same time, the pumping unit on the pipeline shuts down and an alarm activates.

A third safety system that can be installed on a line to detect any variance is a low pressure shutdown on the pumping unit. Upon detection of abnormally low discharge pressure the pump is immediately shut down.

The use of block and check valves on line sections that cross waterways are also vital safety factors to minimize a spill in a watercourse. The block valve can be either manually or remotely closed to restrict natural flow in the line after pumping has ceased. Naturally a remotely closing valve is preferable since the time factor for a worker to get to and close the block valve is eliminated. By positioning a one-way flow check valve on the line on the opposite side of a waterway backflow is restricted and the only oil released is that contained in the line between the block and check valves.

In short, in addition to control of operations at manned locations, it is possible to maintain constant and complete control of operations for the full length of the line. Through the medium of a computer the entire system can be scanned as frequently as every ten seconds. Any change from the previous 10 seconds will be indicated to the line operator on his control panel. The operator can rapidly assess the change and in the shortes possible time, instigate cation to stop or start units, close valves, etc., to mitigate any deviation from normal operation.

7.2.1 Planning the Line

Although the markets develop the general location of the line the most desirable route to a given terminal can be rapidly evaluated from detailed topographic maps and by aerial survey. The survey might use plain and infrared or multispectral photography. From these surveys a ground survey of the right of way can be instigated. Wherever possible the crossing of waterways and wetlands should be held to a minimum since they can definitely be considered as potential trouble spots in the event of an accidental leakage.

Aerial photographs can be used to advantage in the development of an SPCC Plan. The photography can help to determine where spill response equipment can best be stored for fast deployment. The maps and aerial survey will indicate heavily industrialized and populated areas which, as far as practical, should be avoided. Environmentally sensitive areas should be by-passed; this would include spawning areas such as wetlands, marshes, etc. Attention to this factor should aid greatly in gaining a permit to construct the line.

The selection of materials is also of major importance. High yield and tensile strength pipe of seamless or electric weld pipe offers many advantages over lap or butt weld pipe. Pipelines also benefit greatly from economies of scale--the larger the pipe diameter, the lower the transportation cost will be. An initial high cost will be returned by the ability to transport more product with an energy saving over the life of the line. Engineering computer programs can be run to determine the correct size of pipe to gain maximum throughput. Additionally the final selection of pipe should insure that it will meet the maximum stress requirements that will be placed on the system. The pipeline industry has determined from years of experience that pipeline joints need special attention. At least 15 percent of all girth welds should be x-rayed for welding defects (this exceeds federal requirements by a factor of 5 percent) and 100 percent of road, railroad, and river crossing welds should be x-rayed (federal law requires only 90 percent testing).

7.3 Corrosion Prevention

7.3.1 Internal Corrosion

Maximum protection can be gained from keeping both the product and the line free of water. The products can now be treated with rust inhibitors. It is advisable that even the water used for hydrostatic testing of the line be treated with a rust inhibitor.

7.3.2 External Corrosion

This is one of the principal factors in line failure especially when the pipe is buried and hidden from view. Bernard Husock, P.E., Vice President, Harco Corporation, Medina, Ohio*, stresses four factors related to underground corrosion.

". . .1. Corrosion of iron and steel is a natural process.

2. All ferrous metals corrode at essentially the same rate.

3. Corrosion of iron and steel underground or underwater results in selective and concentrated attack.

4. Once leaks start to occur on an iron or steel pipe, they continue to occur at an exponentially rising rate. . ."

This paper provides the following definitions for the two basic mechanisms responsible for underground corrosion.

- "Electrolytic Corrosion: Electrolytic corrosion is a result of direct currents from outside sources. These direct currents are introduced into the soil and are picked up by an underground pipe. The locations where the current is picked up are not affected or are provided some degree of corrosion protection. But the locations along the pipe where this current

---

*Causes of Underground Corrosion. Paper HC-36, 21st Annual Appalachian Underground Corrosion Short Course. West Virginia University, May 1976.

leaves the pipe to enter the soil, those locations are driven anodic and corrosion will result. The corrosion of an iron or steel pipe under this influence will be at the rate of 20 pounds per ampere per year. This type of corrosion is often referred to as stray current corrosion. If the outside source of current is a cathodic protection rectifier on a pipeline belonging to others, the corrosion problem is referred to as an interference problem.

- Galvanic Corrosion: Galvanic corrosion is the self-generated corrosion activity which results when the pipe is placed in the soil. Differences in potential develop along the pipe or between different pipes. These differences can result from dissimilar metals placed in the soil or they can develop on the same metal as a result of differences within the soil. These potentials generate corrosion currents which leave the metal to enter the soil at anodic areas and return to the metal at cathodic areas. Corrosion occurs at the anodic areas where current leaves the metal to enter the soil."

Based on this information (with certain restrictions that follow), resistivity testing of the soil on a pipeline route may be a beneficial factor. The following table was also drawn from Mr. Bernard Husock's technical paper.

TABLE 7-2

SOIL RESISTIVITY CLASSIFICATION:

Resistivity--ohm-cm	Category
0 - 2000	Very corrosive
2000 - 5000	Corrosive
5000 - 10,000	Moderately corrosive
10,000 - 25,000	Mildly corrosive
Over 25,000	Progressively less corrosive

The paper continues with the following precautions.

. . ."This classification is not intended to be considered as an exact guide for classifying soils according to corrosiveness. It merely serves to indicate that the corrosion rate is lower in soils of higher resistivity. However, it must be appreciated that if a pipe is in the ground long enough, it will develop leaks even in soils of more than 25,000 ohm-cm.

In addition, there is a further complication encountered in the higher resistivity soils. Large variations in resistivity within relatively short distances are often seen in higher resistivity areas. It is not unusual to have variations in resistivity from less than 10,000 to more than 100,000 within 500 feet of pipeline right-of-way. These variations in themselves indicate variations in soil composition which can be responsible for the promotion of galvanic corrosion activity. . ."

There are some positive ways of retarding the deterioration process of a buried pipe as follows.

- The pipe should be abrasive blast cleaned and painted with a protective coating such as asphalt, coal tar, somastic, and polyethelyne tape, or any proven synthetic coating developed for pipeline protection. The coating should be the one determined to provide the best protection for the soil condition at the trenching location (Figures 7-1, 7-2, and 7-3).

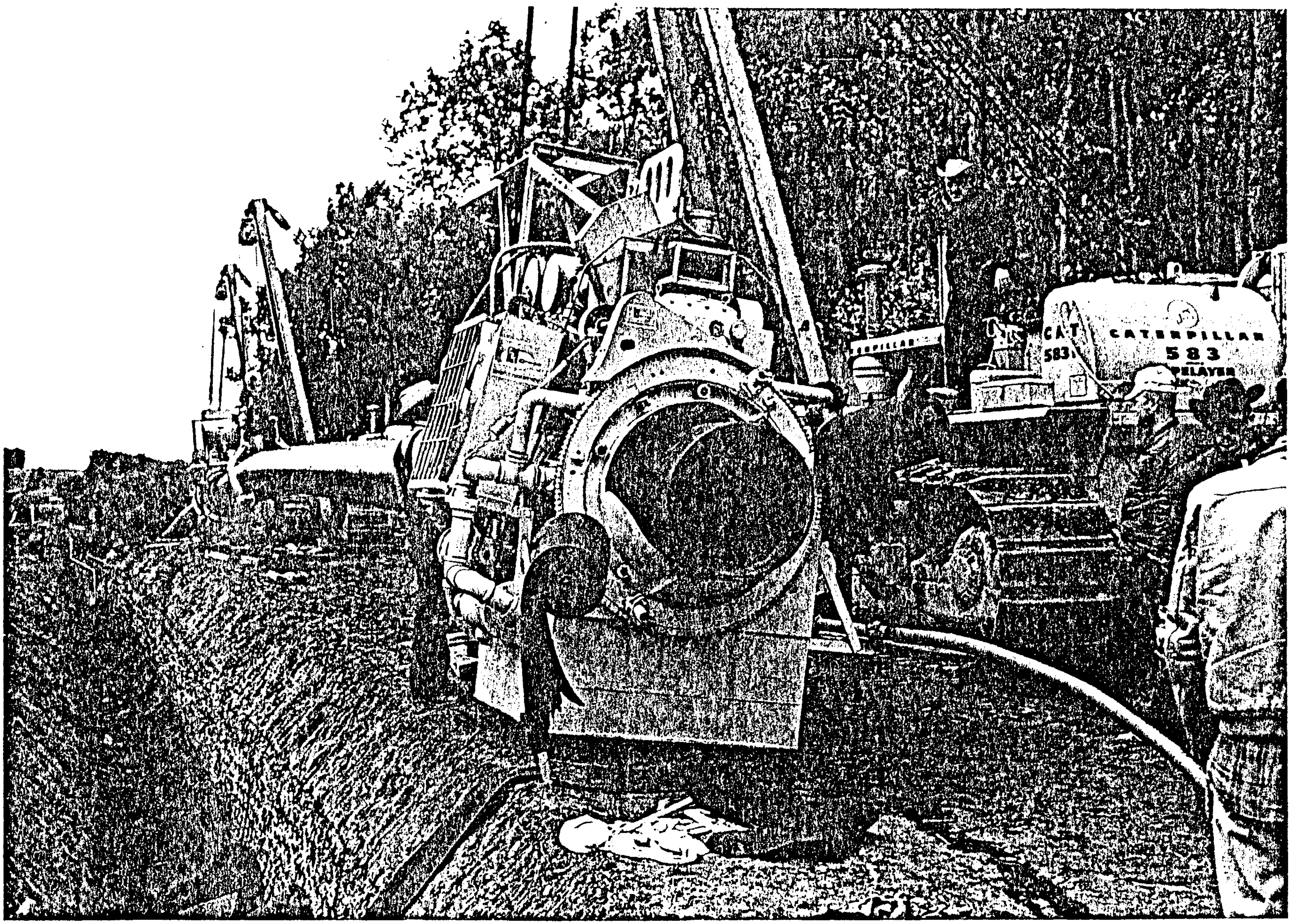


FIGURE 7-1. Hot Applied Coal Tar Enamel Installed Prior to Burial of Line (Figure Courtesy of Koppers Co., Inc.)

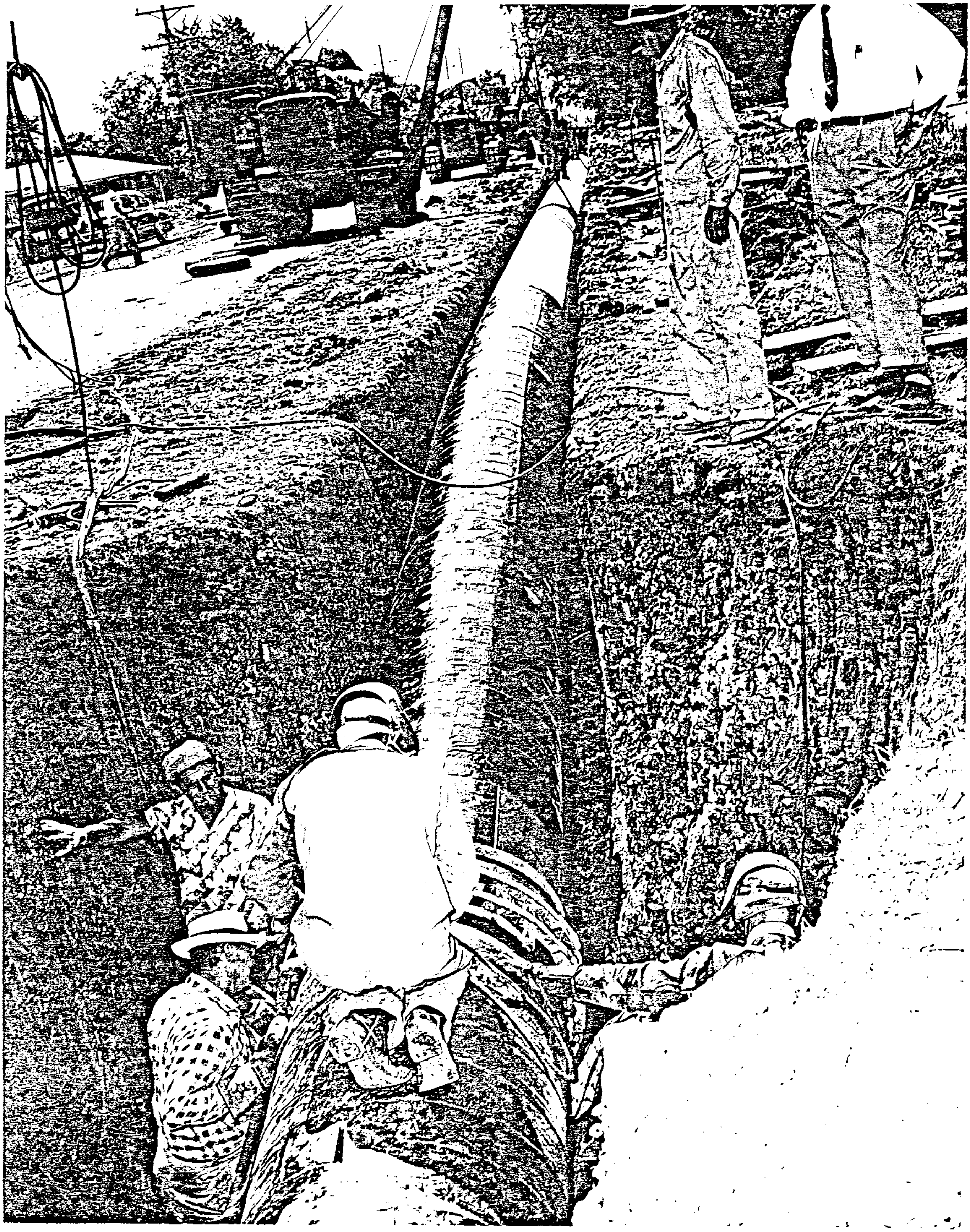


FIGURE 7-2. 36" Pipeline Tapecoat 20 Application Process

36" Pipeline being laid in a residential area that has been coated with Tapecoat 20 (Hot Applied Coal Tar Coating) is a bend which goes down in the ground more than 14'. The men in the ditch are making a tie in weld and are making sure that the pipeline is properly lined up prior to making the weld. (Photograph Courtesy The Tapcoat Co., Evanston, Illinois)

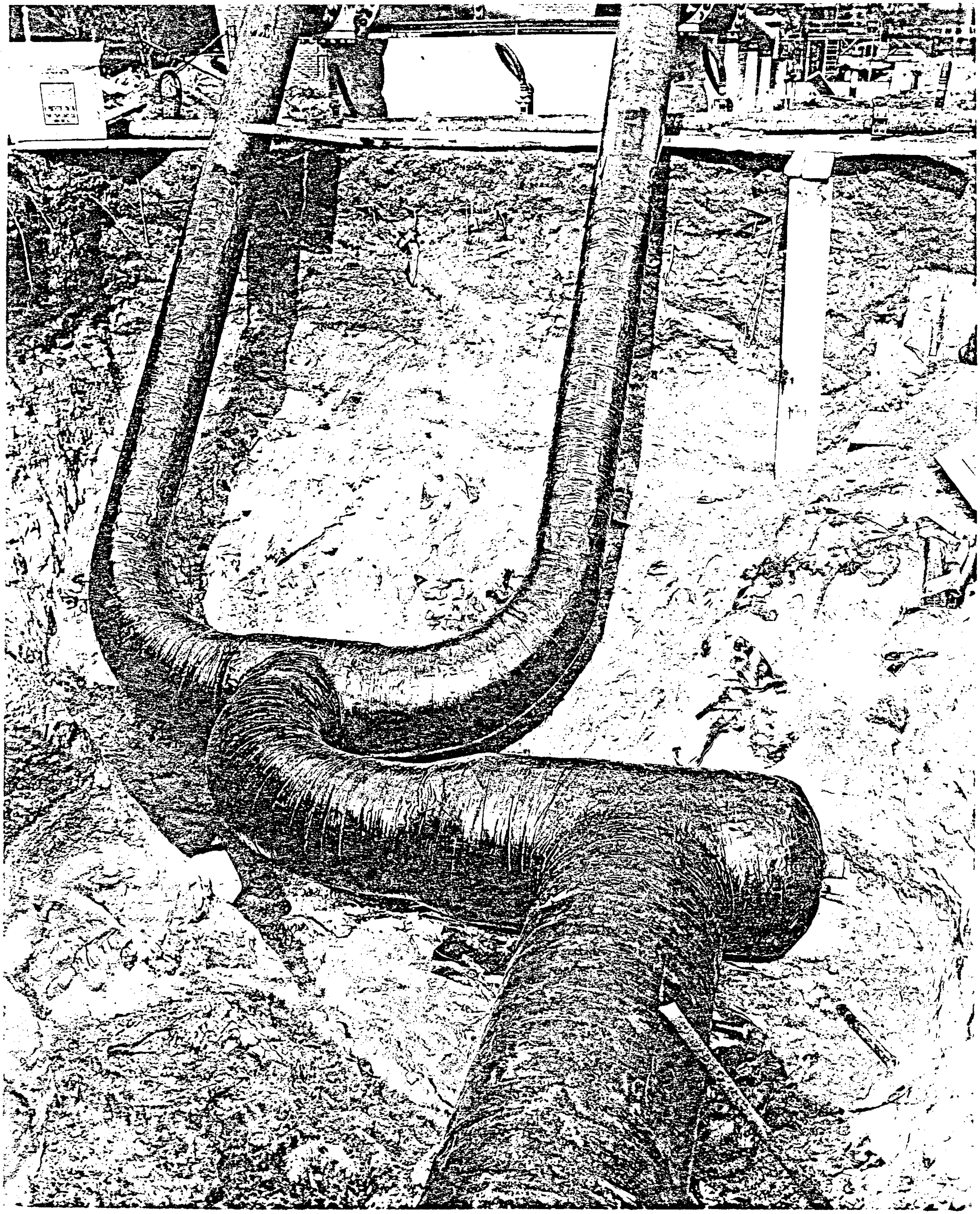


FIGURE 7-3. Hot Application of Tapecoat 20 Coal Tar Coating (This particular installation was applied 20 years ago.) Photograph Courtesy The Tapecoat Co., Evanston, Illinois

- Under Federal law it is also mandatory that a buried or submerged line be protected by a system of cathodic protection. A typical protection system involves connecting the pipeline and a sacrificial annode, generally graphite or magnesium, to a D.C. rectifier as a source of electrical current. A controlled quantity of current is then passed through the soil and to the pipeline. In this manner the annode is corroded instead of the pipeline metal. Regular testing of the system and renewal of the annodes is obviously warranted. (Figure 7-4.)

Specific details on Federal requirements for operation and maintenance of overland pipelines can be found in CFR 49, Part 195 as revised October 1, 1979.

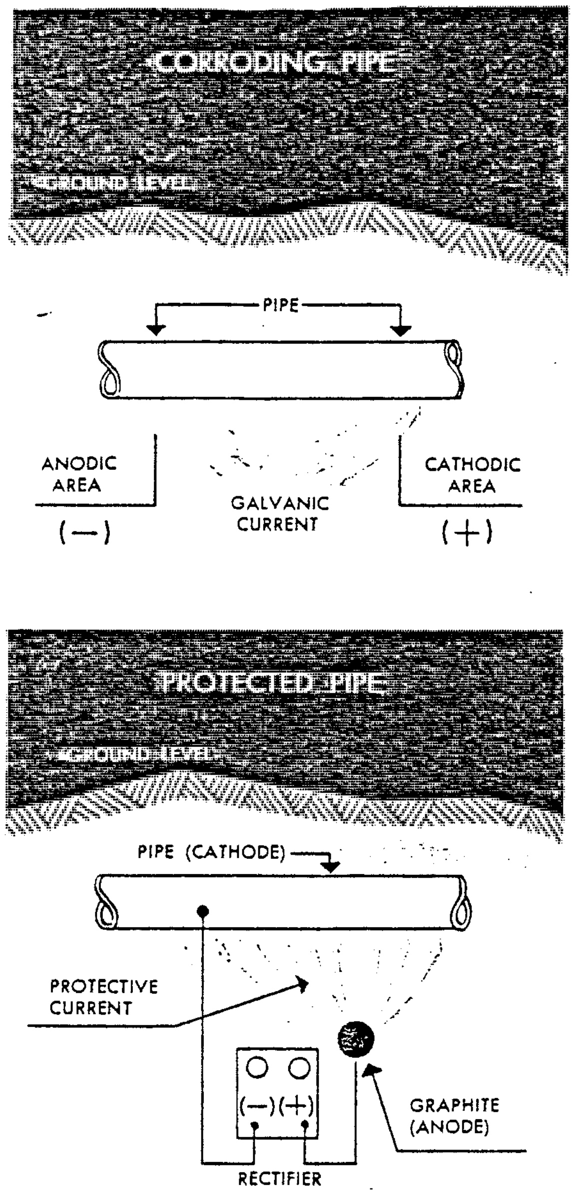


FIGURE 7-4. Corroding and Protected Pipe
(Illustration Courtesy Harco Corporation, Medina, Ohio)

8. TANK TRUCK LOADING/OFFLOADING RACKS

8.1 General

Considering the vast amounts of flammable petroleum liquids handled daily through truck loading/offloading racks, the losses due to spills, explosion and fire have been relatively small in number. However, a single incident can be catastrophic. The trucking industry is growing more and more each day and the risk potential increases in proportion. An upward trend in losses in recent years prompts the need for better loading rack design and enhanced training for those who operate them. This would include company-employed loaders and common carrier personnel who conduct their own loading operation. The following factors (as researched by Industrial Risk Insurers Company, Hartford, CT) contribute to losses at loading racks.

- Faster loading rates which run between 500 and 1200 GPM (0.03 to 0.07 m^3/s).
- Extensive use of product filters which are prolific producers of static electricity.
- Drier, cleaner products especially in the distillate range which retain their static electric charges for longer periods of time.
- Increased handling of more hazardous products such as jet fuel (JP4), benzene, toluene and xylene, which, because of their vapor pressures, present longer exposure to vapor conditions within the tank compartment which are within the flammable range.

- Extensive use of large capacity aluminum tank trailers which are prone to structural failure within a period of one minute when exposed to intensive ground fires.
- Larger and more complicated loading racks which are designed to handle many large trucks at one time. Some up-to-date racks are equipped with extensive automated data processing equipment for recording and billing deliveries.
- Limited availability of real estate at some locations which not only creates congestion and complicated truck traffic patterns, but also exposes adjacent tankage and facilities to fire.
- Key-stop (unattended) operations are gaining more attention with the result that there is less supervision over loading practices and less possibility of controlling fires once they have started.
- Labor turnover at loading racks is higher today. Loaders are not as well experienced as in the past.

In order to minimize losses and to attain a safe, productive record, it is necessary for all those concerned with loading rack operations to fully understand the inherent hazards, especially those related with the hazardous practice of "switch loading" which involves loading a vehicle with a product other than the one previously carried.

In general, industry needs to design better loading racks and to renovate existing racks so as to minimize operational hazards , to constantly educate loaders and truck drivers in the safest loading/offloading practices and to implement the best possible engineering protection which can be effectively used to control spills and/or fires.

8.2 Construction and Location of Loading Racks

Proper, adequate spacing of loading racks is of primary importance both against exposure fires and for control of fire emergencies and spills on the racks themselves. Table 8-1 illustrates the recommended spacing for loading racks as developed by Industrial Risk Insurers Company.

TABLE 8-1.

Spacing of Truck Loading Racks

MINIMUM DISTANCE IN FEET	PRODUCT TANKS	LPG TANKS	LOADING RACK	PUMP HOUSES	SERVICE BUILDINGS	DOCKS	FIRE PUMPS	FIRE HYDRANTS	COMPRESSORS	PROCESS UNITS
LOADING RACK	250	100	50	200	200	200	150	100	200	200
	76.2 m	30.5 m	15.2 m	61 m	61 m	61 m	45.7 m	30.5 m	61 m	61 m

Loading racks should be constructed entirely of noncombustible materials. In no case should materials such as wood decking, wood stairs, wooden ramps and frame enclosures for the protection of loading personnel be used. Roof sheeting should also be noncombustible, without the use of tar or asphalt as coatings or sealing materials. Racks should be limited in size to accommodate no more than six trucks at one time. Larger installations should consist of no less than 50 ft. (15.2 m) open space between structures.

Proper drainage of loading rack areas is extremely important in loss prevention and control in the event of a fire. Rack areas should be fully paved, curbed, and drained (Figures 8-1 and 8-2) so that any spill from trucks or equipment would quickly flow to trapped drains capable of removing the hydrocarbon liquid without any back-up of liquids at the drain.

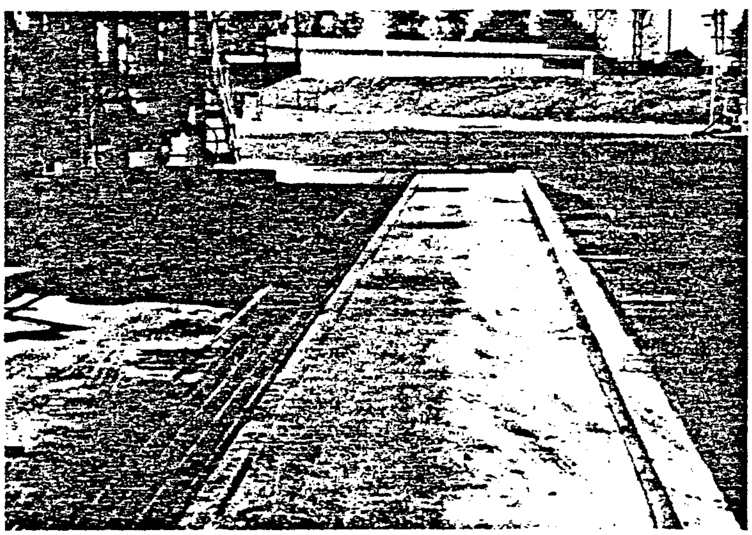


FIGURE 8-1. Truck Loading Rack Drainage

This depicts a well drained and curbed loading area; however, center drain exposes the underside of truck to possible fire and/or explosion. Water spray heads have been installed in the metal grating for added protection. (Photograph courtesy IRI Company)

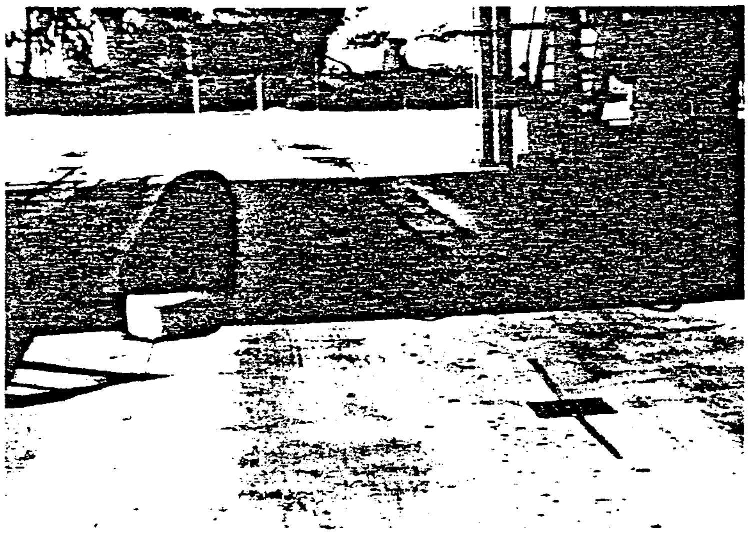


FIGURE 8-2. Preferable Truck Loading Rack Drainage System

This illustrates a better drain arrangement where spills would quickly pass into catch basins out from under the tanker trailer. Note good area curbing.

Drains should be located out from under the trucks on the outboard side of the rack and should be frequently checked to see that they are clear of debris and blockage.

In situations where pumps, additive storage tanks, or undiked product storage tanks are located uphill from the loading rack, diversion dikes should be installed to prevent any hydrocarbon leaks from entering the rack area. Conversely, if the loading rack is located uphill from other hazardous or valuable property, diversion dikes should be provided to stop possible spread of fire from the rack to those areas. Any oil storage in drums or tanks should be stored within a confined (walled or curbed) area, with sorbent materials spread within the contained area to contain spillage and drippings. They should be kept as remote as possible from the rack.

Curbing or guards of sufficient strength and height should be installed around the loading islands to prevent trucks from striking and damaging the rack. Enough space should be provided so that even the largest trucks have ample turning radius when entering or exiting the rack. Spacing should be provided for trucks to park 100 to 200 ft (30.5 to 61.0 m) from the rack while awaiting a turn to load or to effect minor repairs. Loading racks should be located as far as possible from tankage and other hazardous structures, such that trucks would not have to pass through any other potentially hazardous areas between the street and the rack. Separate entrance and exit gates should be implemented to prevent possible truck collisions and jam ups. Finally, safety signs should be properly posted at conspicuous locations to constantly remind rack personnel of concern for safe loading practices.

Closed circuit television monitoring systems have been found useful for the supervision of loading/unloading racks. A well positioned monitor in the plant office can provide a means of viewing the operational procedures. These devices present an opportunity to observe unsafe acts or conditions which may occur during daily operations. A typical installation would cost $5,300 plus an installation cost of around $1,000.

8.3 Static Generation

Electrostatic generation in hydrocarbons passing through piping is not critical since turbulence is usually low and any charges generated quickly dissipate to the metal piping. However, hydrocarbons passing through product filters utilizing cotton, paper or felt elements generate strong static charges, requiring at least 30 seconds of relaxation time to dissipate in the flow between the outlet of the filter and the tip of loading tube. (Longer lengths of pipe and special relaxation chambers yield additional relaxation time if needed.)

Currently, industry is placing more emphasis on higher purity products, particularly as produced by hydrodesulfurization. The 30 second relaxation time formerly thought to be adequate may now be subject to serious questioning. Surveys of test results indicate a significant increase in relaxation times from 100 to 500 seconds (1.6 to 8.3 min.) or more under some conditions.

Electrostatic charges are also generated as the oil enters the truck tank compartment. The intensity is proportional to the amount of flow turbulence which itself is dependent upon two factors: the rate at which the product enters the compartment, and the design of the loading tip. Several oil companies, in the hope of reducing spills, have investigated various loading tip designs. The straight tips, (formed by cutting a loading tube at 90° angle to its centerline), seem to cause turbulence and a tendency to be thrown upward when loading is initiated. A loading tube cut at a 45° angle to its centerline, however, has satisfactory turbulence characteristics at a moderate flow and is the least costly of the two. Construction of all loading tubes should be metal and of sufficient length to rest on the bottom of the tank compartment.

The loading rates of jet fuels (JP4), benzene, toluene, xylene, or distillate class materials after handling gasoline (switch loading) should not exceed a velocity of 3 feet per second (0.9 m/s) until the outlet is completely submerged. The full loading rate should then not exceed 15 to 20 feet per second (4.6 to 6.1 m/s). This shifting in rate can be accomplished by utilizing a special loading regulator tip as shown in Figure 8-3.

The special loading tip automatically shifts to the full loading rate when submerged to a safe depth. The circular deflector tip design minimizes spraying and splashing and prevents the loading tube from being jolted out of the tank compartment when loading has begun.

Instances of disasters caused by static electricity are plentiful. In one example, case history No. 30,081 from Industrial Risk Insurers (IRI) Company, ". . .A diesel-powered

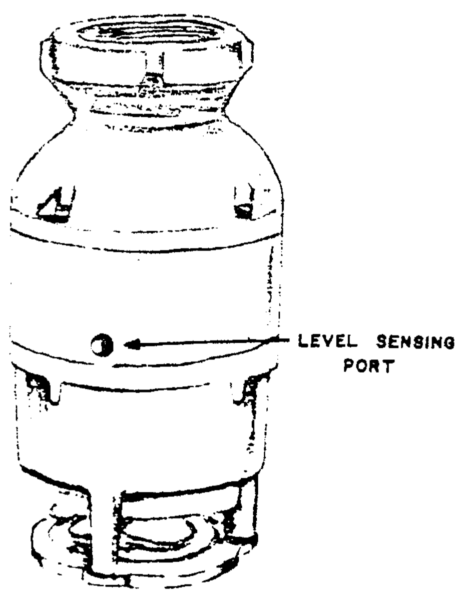


FIGURE 8-3. Loading Regulator Tip

tractor pulling an 8,600 gallon (32.5 m^3) aluminum trailer was being loading with #2 fuel oil when there was an explosion and subsequent fire. The driver had pulled in at rack and had started to load. The meter showed 6,379 (24.1 m^3) gallons had been loaded when there was a terrific explosion followed by fire. The yard man shut down the nozzle. The foreman called the fire department, threw the pump disconnect switch, and actuated the emergency valves. The fire chief and foreman checked the truck and found the ground wire was in use and the ignition key was in the "off" position. Static electricity caused by fast loading of the fuel oil appears to have been the source of ignition."

Causes other than static electricity can readily ignite explosive vapors. In another example a gasoline transportation vehicle had crossed town in an empty status; the travel greatly increased the vapor content in the cargo compartment. Upon arrival at the loading terminal, the maintenance supervisor climbed on top of the tank to inspect the loading dome which was reported as having a defective gasket. A cigarette lighter (found in the aftermath) fell from the supervisor's shirt pocket into the vapor filled tank. The fall activated the lighter which in turn caused an explosion. The worker was blown 60 ft. from the vehicle. Although badly injured he survived the ordeal. However, the vehicle and the loading rack was a total loss as a result of an ensuing fire. Naturally sources of ignition such as lighters, matches, and sparking tools, etc. should be prohibited in loading/ unloading areas.

8.3.1 Neutralizing Static Charges

"In-line" static charge neutralizers are helpful in reducing static by producing charge gradients. Such devices are constructed of a plastic insulator tube enclosed in a metal housing provided with sharp grounding points. They should be installed downstream from filters, pumps and other static charge generating equipment. These neutralizers remove the static electrical hazard from the oil before it reaches the loading tip but they have no effect on charges caused by excessive turbulence at the loading arm tip.

Specially formulated additives known as fuel conductivity or antistatic additives are most often used in petroleum distillates such as kerosene, furnace oil, and diesel fuel since these fuels have a tendency for higher charging, lower conductivity and lower vapor pressures. Even proper grounding of low conductivity fuels does not guarantee that charges will not accumulate in a receiver resulting in significant surface voltages. If this surface voltage exceeds the critical set value, an incendiary discharge between the fuel surface and the receiver interior may occur in the available vapor space which can ignite a flammable fuel/air mixture. These additives increase fuel conductivity and increase the dissipation of electrostatic charges through the fuel. Low concentration of these additives will increase fuel conductivity to 50 picosiemens/meter. (Studies indicate that a fuel with a conductivity of 50 picosiemens/meter will satisfactorily dissipate electrostatic charges.) There are several different models of meters available which are designed to measure fuel conductivity in picosiemens/meter directly and are simple to operate.

Although these additives serve to protect against accidents caused by equipment failure and human error, they should not be used in lieu of well-designed equipment and proper operational practices.

8.3.2 Bonding

Bonding involves the joining of two pieces of metal with a wire to eliminate the probability of a spark. Good bonding is essential between the loading rack and the tank truck to eliminate sparking at the hatch. The bonding or grounding cable should be attached before the loading pipe is inserted. Bonding is usually accomplished by means of a heavy flexible copper or stranded steel cable securely attached to a product pipe riser at one end and clamped to the compartment shell being loaded at the other end using a heavy-duty alligator clip or pressure clamp. In most cases trucks will have permanently attached special bolts made of noncorrosive material with spherical heads. The bonding cable would then be equipped with a pressure clip to match the spherical bolt head. The condition of alligator clips, especially the joint between the bonding wire and the clip, should be periodically inspected by other than rack personnel to insure effective bonding circuits. This is a very important factor since vehicles are frequently driven away from the rack without disconnecting the bonding wire. Some organization place a barrier over the truck's windshield as a reminder to the driver that all connections fill line and grounding wire be disconnected before pulling away from the rack. As long as the resistance in the circuit does not exceed 1×10^6 Ohms, the electrostatic bonding is considered adequate. In some designs, loading rack ramps drop down and the vehicles back into the ramp to offload. The rear of the truck can then make physical contact with a bumper stop or concrete wall. This is not an effective electrical bonding for loading/offloading operations.

8.3.3 Grounding

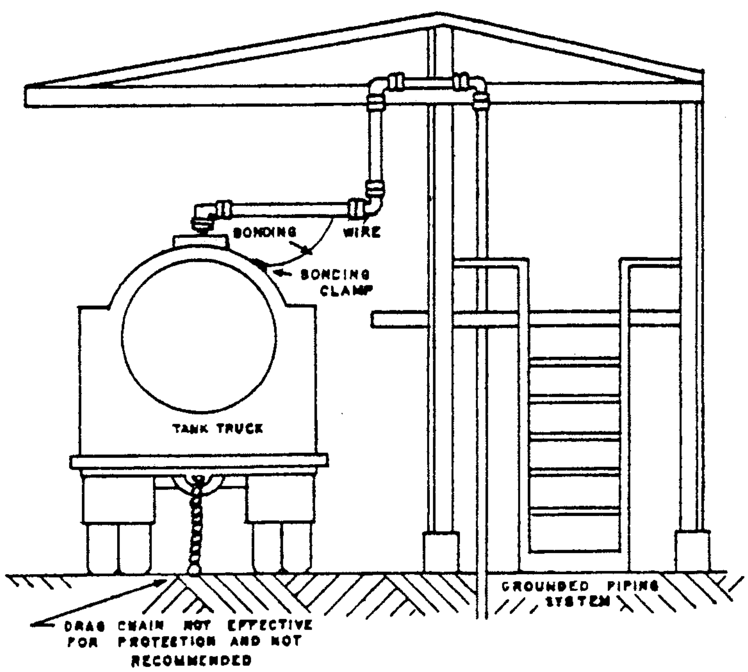


FIGURE 8-4. Grounding tank trucks immediately after the truck is spotted and before the loading spout is inserted. (Illustration Courtesy API Corp.)

In the concept of grounding, the bonding system is electrically connected to the earth so that any static charges or stray electrical currents from the truck are led to a common ground. The testing of proper rack grounding is accomplished by using a common Volt/Ohm meter attaching one end to the rack and the other end to a earth ground (i.e., fire hydrant or water pipe). Readings in excess of 10,000 Ohms show extremely poor grounding and correction is recommended. Resistance is usually less than 5 Ohms on good grounding.

"Electrostatic Drain and Ground Indicators" can be used on loading racks. These indicators have signal lights to indicate safe grounding conditions. They can also be arranged so that loading pumps cannot be started unless proper grounding has been established. This feature proves very effective especially where loading racks are left unattended and loading is conducted by individuals other than company employees.

8.4 Control of the Atmosphere Above the Oil

The control of the atmosphere above an oil cargo involves the reduction in oxygen level in the compartment being loaded to a point where combustion cannot take place. Ordinarily with gasoline and other products having a Reid Vapor Pressure above 4.5 psi (0.3 kg/cm^2), the vapor in the compartment is "too rich" to burn and need only be properly bonded. Intermediate products having Reid Vapor Pressures below 4.5 psi (0.3 kg/cm^2) and a flash point below 100^{0}F (37.7^{0}C) produce concentrations within the flammable range which can easily be ignited by static charges on the surface on the oil. To achieve maximum safety in loading these products, oxygen levels in the compartment can be reduced below combustion levels. This can be accomplished by injecting sufficient amounts of CO_2, nitrogen, or inert gas into the vapor space before loading. Another practice which yields the same result is gas blanketing the compartment with fuel gas or heating the oil sufficiently to maintain a "rich" vapor condition over the oil.

Currently, these practices are not generally followed due to the time consumed and the extra expense involved. The only alternative, which does carry some degree of risk, is to minimize static potential as discussed in the preceding sections.

8.5 Switch Loading

The practice of switch loading and the hazards associated with it accounts for 70-80 percent of serious losses reported at loading racks; as a result, switch loading merits special attention from all those connected with loading rack safety.

Switch loading is the loading of low vapor pressure products into a compartment which previously contained a high vapor pressure product (e.g., loading kerosene or diesel fuel into a compartment previously containing gasoline). A flammable vapor space is present over the lower vapor pressure product because the compartment has been partially ventilated when unloading the previous load of gasoline, thus reducing the "over rich" condition to a flammable one. The lower vapor pressure product usually retains static charges long enough to develop a potential ignition source. Switch loading losses seem to occur most when compartments are one-quarter to one-third full and when temperatures are close to 30°F (-1°C). Proper bonding and grounding has no effect in preventing such losses since the spark discharge in switch loading ignitions occurs between the oil surface and metal of the fill pipe or truck compartment. As previously discussed, the switch loading hazard can be eliminated by injecting sufficient quantities of an inert gas (i.e., CO_2 or nitrogen) into the vapor space prior to loading but time and added expenses tend to negate such action. The principal means of switch loading fire prevention would be to eliminate the practice altogether. In all practicality, this cannot be done but much can be accomplished by proper dispatching to reduce switch loading to a minimum.

Another instance (Figure 8-5) illustrates where proper safety precautions were not used, Case History No. 18,576, IRI Company, is as follows: "A tank truck which had formerly carried gasoline was being switch loaded with a distillate. The rack was equipped with positive ground indicators which indicated that the truck was properly bonded. Wired, brass coupled rubber hose extended approximately 2 ft. (0.6 m) into the compartment. The loading rate through this hose was approximately 18 fps (5.5 m/s); the product was also being filtered. Several minutes after loading began, an explosion occurred. Apparently the difference in electrostatic potential between the liquid surface and the rubber loading hose caused an incendiary spark which ignited the flammable atmosphere."

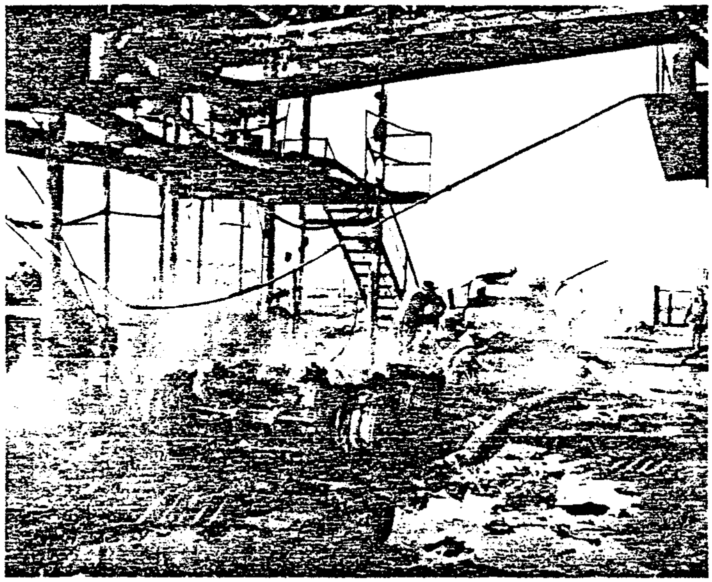


FIGURE 8-5. Switch Loading
This presents the most serious exposure of loading rack disasters. (Photograph Courtesy Industrial Risk Insurers Co.)

By using a proper combination of the following precautions, relative safety in switch loading can be accomplished and instances like Case No. 18,576 eliminated.

1. Reduce filling rates. Initial filling rates should be 3 fps (.09 m/s), then a final rate not to exceed 15 fps (4.6 m/s).
2. The installation of static neutralizing devices on pipe risers handling intermediate oils having Reid Vapor Pressures below 4.5 psi (0.3 kg/cm^2).
3. There should be at least 30 seconds relaxation time for product flows between filters and loading tips. With the current trend towards

higher purity products relaxation time of 100 to 500 seconds (1.6 to 8.3 min.) or more may be necessary to achieve a safe static charge level is products are handled without some type of charge neutralizing device or additive.

4. Special loading arm tips should be installed that produce a minimum of flow turbulence.
5. Loading tip should touch the bottom of the tank.

8.6 Electrical Ignition

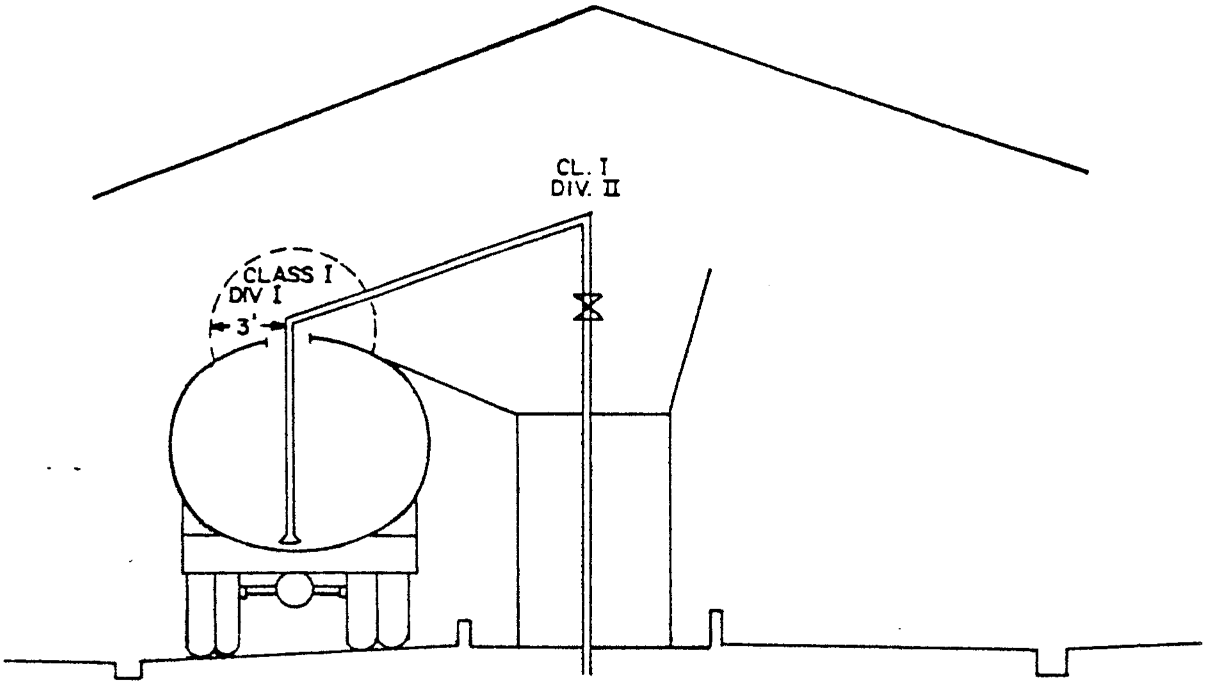
Statistics indicate that electrical energy (other than static electrical charges) is not a frequent cause of fire loss at loading racks; however, it does present an ever-present source of ignition that requires definite precaution. The hazard from ignition where there is a sufficient voltage difference between the truck frame and the loading rack piping can be eliminated by making sure that the truck's electrical system is turned off and that the truck is properly grounded before hatch covers are opened. Also ground wires should not be removed until all hatches have been secured after loading is completed.

It is recommended by IRI Company, despite other standards to the contrary, that all loading racks handling low flash materials be wired to conform to National Electrical Code requirements for Class I, Division II, Group D locations, except within 3 ft. (0.9 m) of possible dome cover openings where Class I, Division I, Group D electrical equipment is required. (See Figure 8-6, "Electrical Classification.")

The Division II area should extend to all points within 25 ft. (7.6 m), to an elevation of 25 ft. (7.6 m), and to all points which are not over 4 ft. (1.2 m) above grade between 25 ft. (7.6 m) and 50 ft. (15.2 m) from the rack. It should be noted that overfilling and possible equipment leaks or failures can rapidly create vapor concentrations within the flammable range throughout the entire loading rack area. Any ordinary equipment (i.e., office calculators, data recording equipment, etc.) needed on the rack should be located in vapor-tight rooms provided with positive air pressure taking suction from a clean air source, preferably a stack terminating not less than 10 ft. (3.0 m) above the roof of the rack or 25 ft. (7.6 m) above grade. This type of installation should incorporate an alarm to indicate sustained loss of proper air pressurization to the enclosure.

All electrical equipment should be inspected periodically to insure electrical safety. Some items requiring inspection are as follows:

1. Make certain that conduit seals are provided within 1.5 ft. (0.5 m) of all arcing devices, such as relays, etc.
2. Proper sealing compound (mastic materials) should be installed in all conduit seals, especially on new additions to the electrical system.
3. All junction and pull box covers must be properly secured.



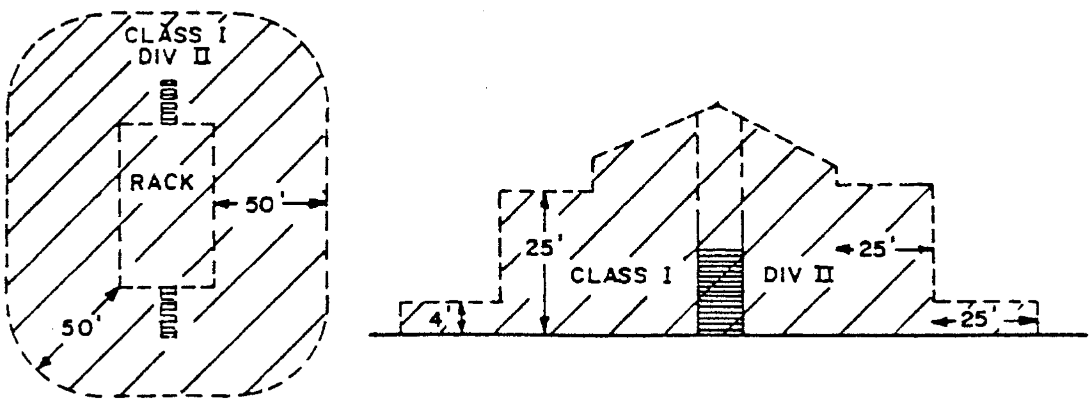


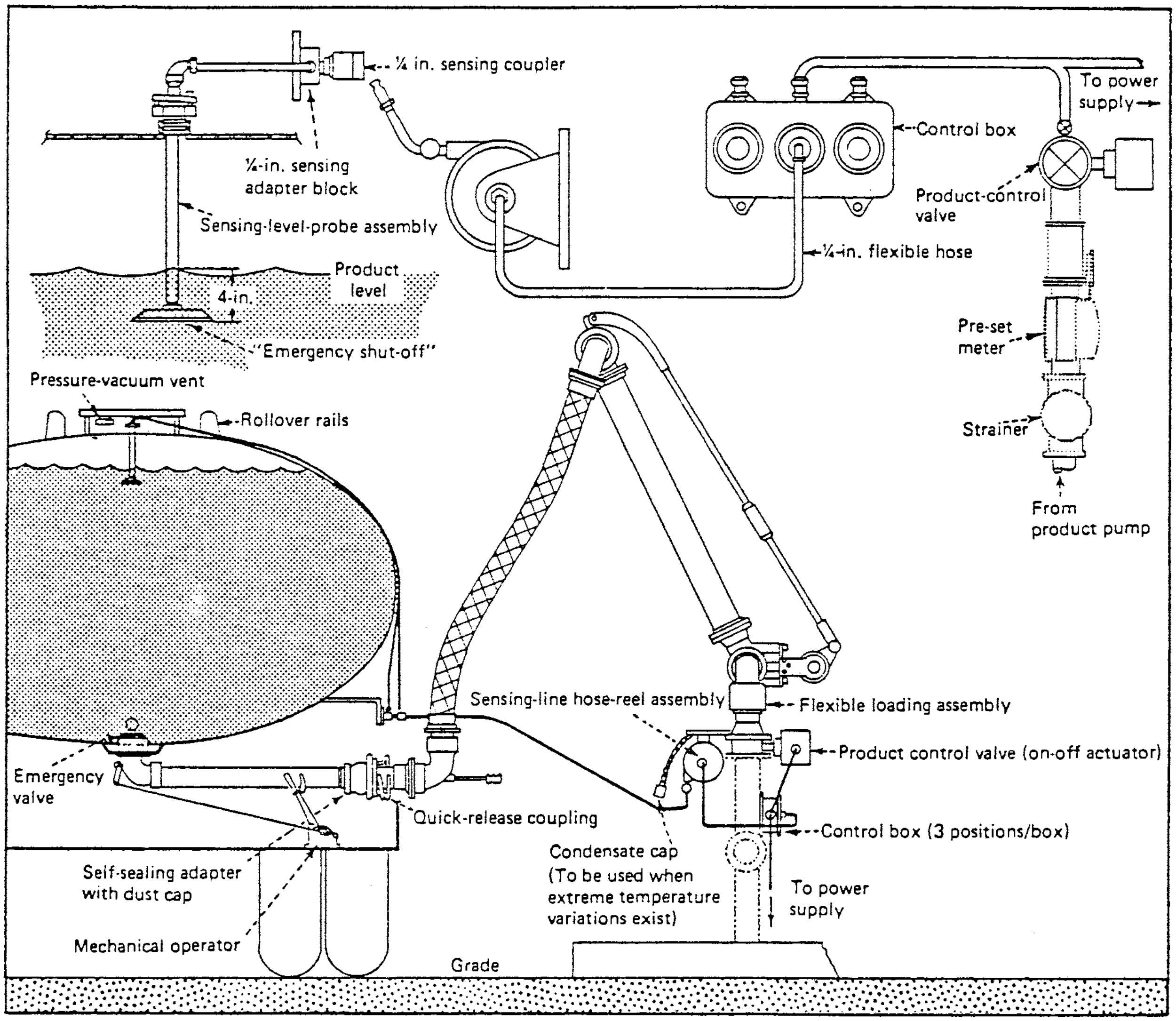
FIGURE 8-6. Industrial Risk Insurers Recommended Loading Rack Electrical Classification

4. Light fixtures should be of explosion-proof design and checked frequently for broken or missing glass globes.
5. Radios, electric fans, etc. should never be used in the area.

8.7 Bottom Filling Operations

New installations of bottom loading racks are no longer frequent in certain sections of the country due to the increasing necessity of vapor recovery type racks in compliance with air pollution authority requirements.

There are some definite advantages of bottom loading. Besides the foremost advantage of being less expensive and less complicated, bottom loading allows faster loading rates, reduced splashing and turbulence, reduced chance of hatch fires (since loading tubes are not inserted) and reduced necessity of personnel needed on top of the tank truck during loading operations. They also develop ease of operation, a cleaner loading procedure, and the elimination of cumbersome counterbalance systems and supporting members. Additionally the metallic loading arms eliminate weak joints such as flexible hoses, bellows, and ball joints. They also eliminate a leakage problem common to sliding arm or telescopic fill lines. When used the sliding section becomes damaged from constant impact with the edge of the fill dome. The uneven section of the sliding sleeve then tears the soft packing installed between the sleeve and the fixed section of line and product leakage results. Figure 8.7 illustrates a typical bottom loading installation.



BOTTOM-LOADING SYSTEM minimizes liquid spillage. Sensing device trips foot valve when tank capacity is reached

FIGURE 8-7.

From: "Transporting, Loading and Unloading Hazardous Materials"
William S. Wood
Chemical Engineering, 6/25/75

Conversion to bottom loading can, however, be a costly procedure. In addition to the cost of modifying the loading rack, all of the tank trucks in the fleet may warrant replacement or costly modification for bottom loading. One organization found vehicle replacement to be the least costly approach to the conversion problem as the modification of older tank trucks to the new loading system was cost prohibitive.

8.8 - Vapor Recovery Loading Equipment

Air pollution authorities requirements and regulations are setting a trend for the use of vapor recovery type loading arms. These arms produce a gas tight fit over the dome hatch and have a separate vapor line which extends to a remote compressor and gas holder (Figure 8-8). The are fitted with float mechanisms to shut off loading when the compartment is full and have short pipes so that products are splash loaded (Figures 8-9 and 8-10).

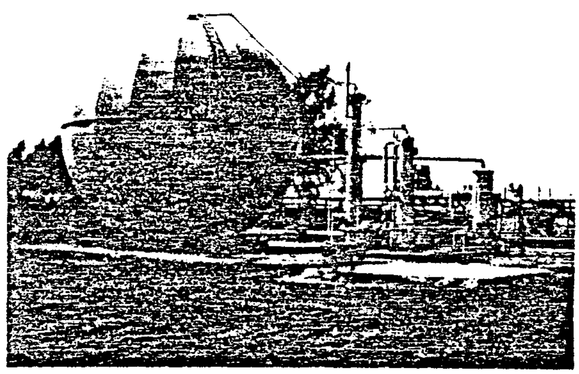


FIGURE 8-8. Loading Rack Vapor Recovery Compressors and Gas Holder.

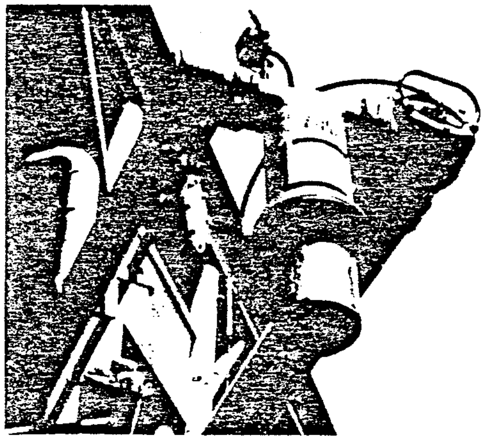


FIGURE 8-9. Hydraulically Operated Loading Arm.

Note short pipe which necessitates splash filling. Photographs Courtesy Industrial Risk Insurers Company.

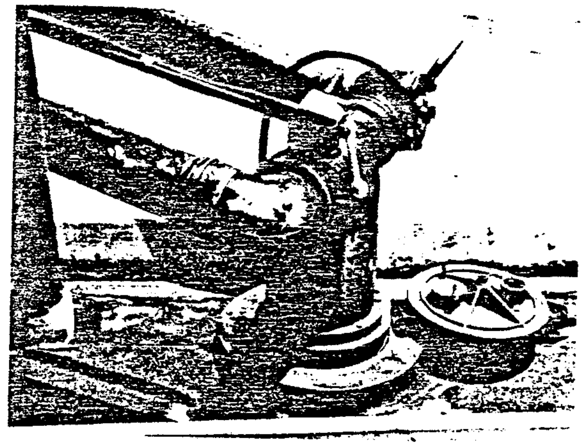


FIGURE 8-10. Loading Arm Inserted Into Truck Hatch.

A float mechanism inside loading pipe shuts off when flow compartment is full

The fill connections provide a double purpose--the load of the fluid while simultaneously recovering the vapors. A single operator can readily handle a bank of these arms. Since the loading arm is automatic when used with set-stop meters. The operator can proceed to the next loading location immediately after each hookup. The systems meet the most stringent local and federal vapor containment regulations. According to one of the major manufacturers, FMC Corporation Fluid Control Division, Brea, CA, all components that require periodic cleaning inspection and lubrication are readily accessible with ordinary hand tools. Maintenance consists primarily of routine inspection of pneumatic controls, debris removal from the control valve, and light lubrication of swivel joints.

Manufacturers claim benefits that include protection against tank overpressuriztion, overfilling, loss of line pressure and

Attended loading racks should have switches capable of killing power to all loading pumps. These switches should be clearly marked to indicate their specific use and should be remotely located from the filling station preferably at the bottom of the stairs (Figure 8-12). Actually, stop switches should be available at each end of the loading rack, with at least one additional switch located not less than 100 ft. (30.5 m) from the rack, in the route of easiest passage (Figure 8-13).

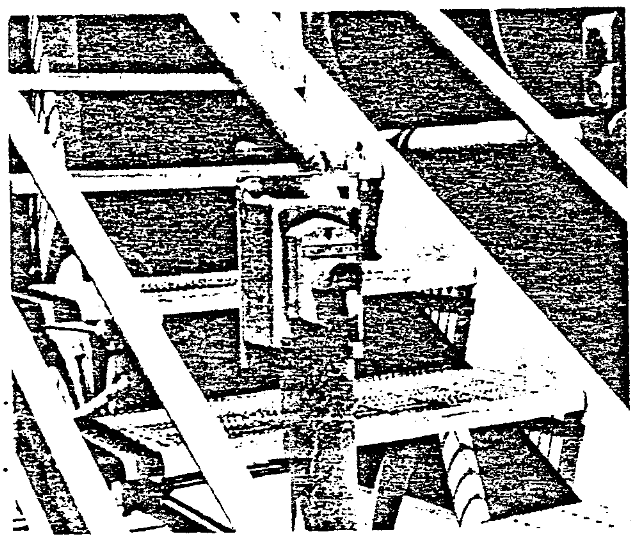


FIGURE 8-12. Emergency Loading Pump Stop Switch Located at Bottom of Rack Stairs

FIGURE 8-13. Emergency Loading Pump Stop Switch Located Remote From Rack at Property Entrance.

Photographs - Courtesy of IRI, Co.

Unattended (key-stop) loading racks should be equipped with automatic fire detection devices which actuate a water spray or deluge system and shut down electrical circuits. The detection devices should be placed over the truck bays and close to the ground where they can quickly react to either a dome fire or a ground fire beneath the truck. There should also be a tie-in between the fire detection circuit and the alarm circuit. The system should provide early warning of the problem to the plant guard house, a central station alarm headquarters, or a local fire department.

In some cases where a moderate hazard exists and mobile water spray cannot be justified, several fixed 500 GPM (0.03 m^3/s) capacity water nozzles should be provided (Figures 8-14 and 8-15). These units should be equipped with the combination straight-stream/fog nozzle tip and should be set back at least 50 ft. (15.2 m) away from the rack. (Actual placement will depend on the area of rack structure; truck traffic patterns; and location of tanks and building.)

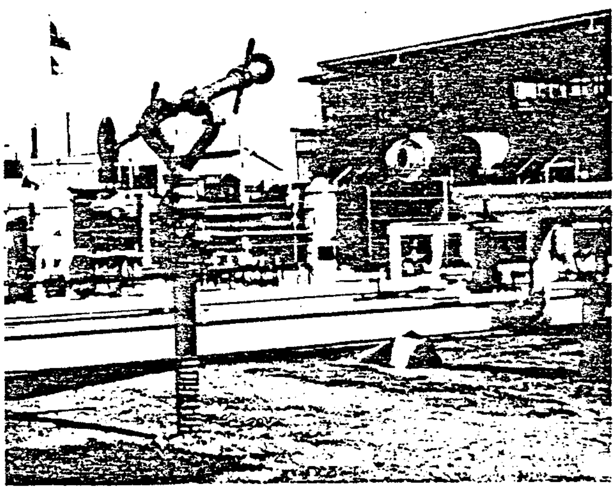


FIGURE 8-14.

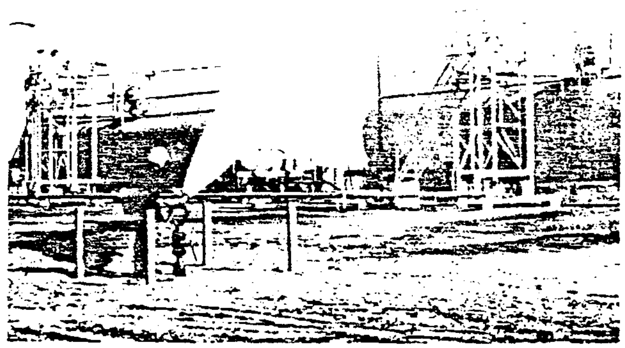


FIGURE 8-15.

Fixed Fire Monitor Nozzels With Quick Opening Valves That Can Provide Protection Between 50 and 100 Ft. (15.3 and 30.5 m). Photographs - Courtesy of Industrial Risk Insurers Company

Dry chemical hand-held and actuated fire extinguishers should be available for use in the event of a loading rack dome fire. At least two 30 lb. (13.6 kg) dry chemical units should be positioned at each loading island, one at platform level (Figure 8-16), and the other at ground level (Figure 8-17). To supplement the hand-held extinguishers, especially in areas lacking special protection systems, 150 and 350 lb. (68 and 158.8 kg) wheeled extinguishers should be used. The larger capacity stationary dry chemical units [i.e., 1000 lb. (463.6 kg) or more] can be used with fixed piping where no fire water systems are available. Also, strong wash down lines should be available at the base of the rack to dissipate spills before trucks can be started and moved. The wash down line can also be used as a first aid supplement in fire emergency situations.

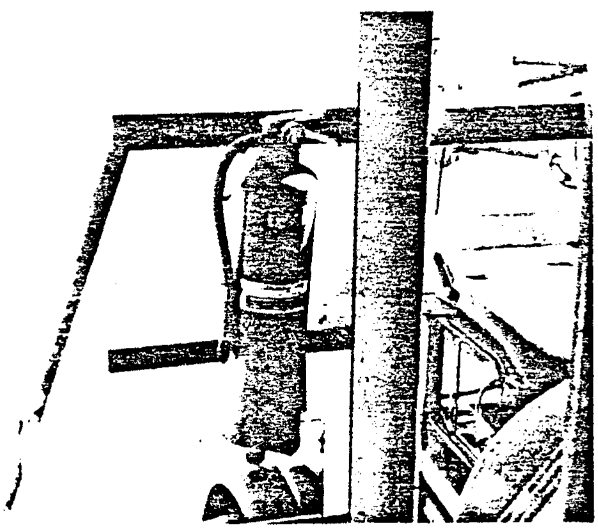


FIGURE 8-16. Dry Chemical Hand Extinguisher at Platform Level.

Photographs - Courtesy of IRI Company.

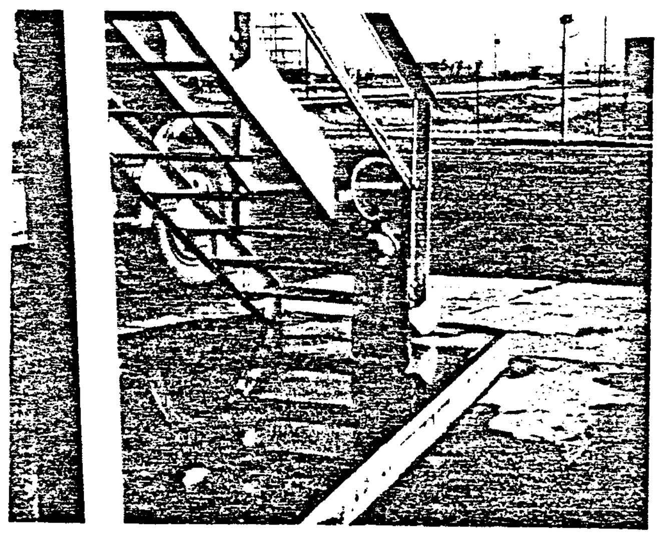


FIGURE 8-17. Dry Chemical Hand Extinguisher at Ground Level.

8.10 Loading Directly From the Storage Tank--No Rack Provided

8.10.1 General

There are some facilities that load tank trucks directly from storage tanks without the benefits and safety features associated with loading racks. This is a fairly standard operational procedure for many domestic fuel oil distributors.

The vehicles are loaded through the medium of the gravity head pressure of the oil within the tank or from gravity gained by elevating the storage tank on cradled supports. Such installations have been found to operate with badly damaged fill hoses. Return reels are not provided and with hoses lying on the ground, vehicles run over and flatten them. Static eliminators and grounding systems are either nonexistent or ignored. The earth in the loading area is frequently blackened and oil saturated from leakage and overfill. The bulk storage tanks more frequently than not lack a secondary means of containment. In many cases, the storage area is unfenced and flow control valves are rarely locked developing a situation ripe for malicious mischief. Clearly there is a need for revision and revamping installations as described.

8.10.2 Design Criteria

One installation has been viewed in the Baltimore, Maryland area that through engineering design has greatly reduced the possibility of accidental spillage when loading directly from the tank.

The vehicle backs down into a graded concrete ramp that is fully curbed at the back and on both sides. Once a bumper stop has been reached the vehicle is in position for loading. At the bottom of the ramp a sump is provided. The sump is of a capacity that it could contain a fairly sizeable overfill. Should this occur, the spilled oil would be pumped back into the storage tank, or, if found to be contaminated, would be disposed of in a nonpolluting manner (Figure 8-18).

Return hose reels are provided for hose protection and the bulk storage tanks are surrounded by earthen retainment dikes. The entire installation was concrete poured and equipped at a cost of $7500 using plant labor. One additional improvement that might have been added is provision of a vapor return hose system; otherwise the loading facility provides a high degree of spill prevention.

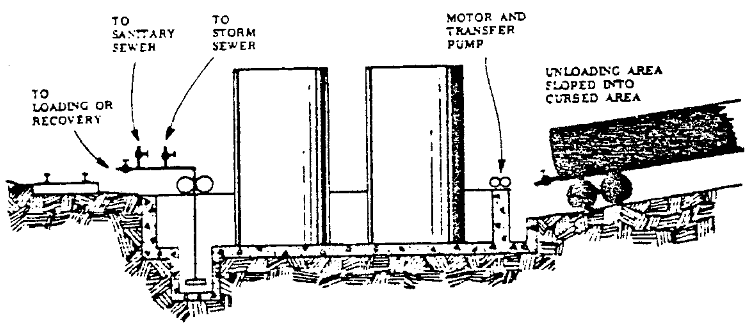


FIGURE 8-18. Containment Curb-Type Spill Catchment System, Depressed Area Form.

From: G. N. McDermott
Journal Water Pollution
Control Federation, Aug. 1971

9. RAILROAD TANK CAR LOADING/OFFLOADING RACKS

9.1 General

Tank car loading areas have been a constant spill source. This statement can be substantiated by examining the earth surrounding the railroad tracks. At most facilities the soil is oil saturated from overspills. Another common cause of spillage develops when rack attendants drain the residue from a tank car directly onto the area between the tracks. The effect of many years of waste drainage has resulted in contaminated ground water, leaching, and seepage. At some plants the problem is so acute that during heavy, rainy periods the ground water physically pumps the oil out of the earth. This to the extent that on the East Coast two plants cannot confine the oil onto their own property. It bubbles out of the earth and flows out of the plants into drainage ditches that side on a public highway.

9.2 Loading and Unloading

Basically loading racks should be of metal construction. Wooden racks develop a fire hazard and the timbers must be frequently replaced due to rot. The rack should be positioned at least 50 feet away from other racks and preferably 200 feet away from other machinery, service buildings, or bulk storage tanks.

Preferably the loading area should be hard surfaced with engineering drainage to spill retention sumps, holding ponds, or surfaced drained to oil/water separators.

Prior to a loading operation, the wheels of the line of cars should be securely blocked in position.

The rack and the truck should be effectively grounded (Figure 9-1) as static charges of sufficient voltage to cause sparking can be generated from the turbulent flow of hydrocarbon products in the fill lines. It is also important that each section of track separated by expansion joints be connected by welding or bolting a bonding cable to the separated track section. Grounding rods for track use could duplicate those described in Section 4.7, Lightning Protection for Bulk Storage Tanks.

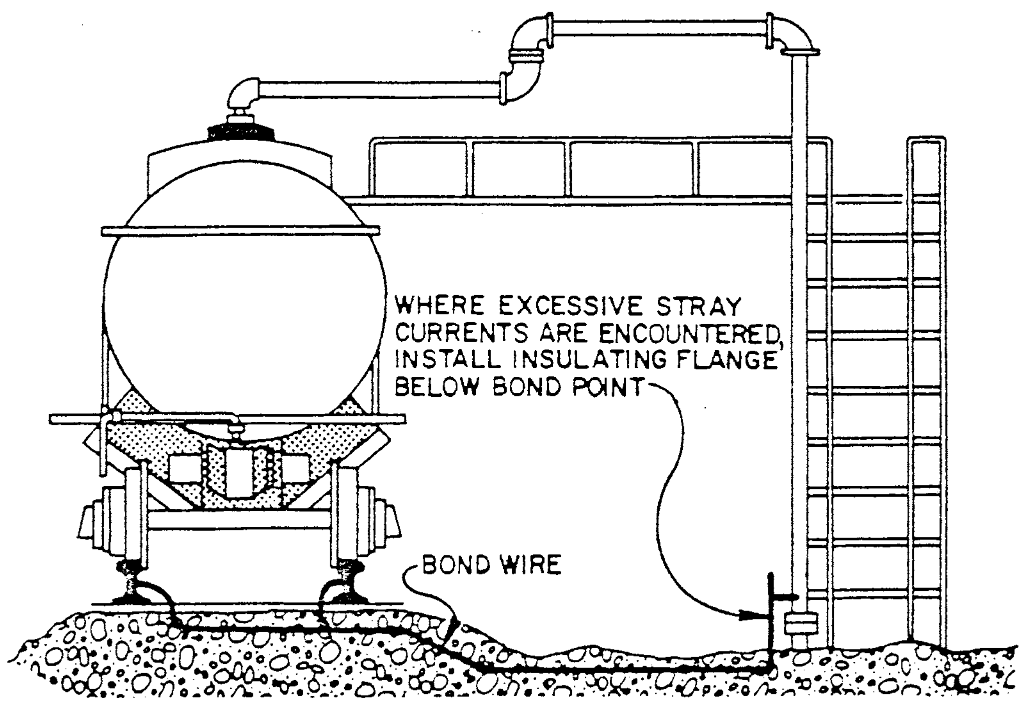


FIGURE 9-1. Bond Rails of Tank Car Loading Spur to Piping
API Illustration

Prior to commencing flow the tank car should be inspected for defects since once filled it can go into immediate shipment and unobserved defects could result in an enroute spill. Typical areas warranting inspection are air brake hoses, couplers, wheels and bearings, and all sections of the under carriage. Once on the route it becomes difficult for the railroad or an individual tank car owner to maintain regular examination of the car.

The bottom drain cap on the tank car should be examined to insure that it has no defects and it should be properly tightened in position. Leaking drain caps can result in a continuous spill enroute with loss of considerable product, possibly the entire content of the tank car. Unfortunately drain caps are never locked in the closed position. Sitting unattended on a side track, marshalling yard, or open track area, the cap is a prime target for sabotage of malicious mischief even though a large cumbersome wrench is needed to loosen and tighten the cap.

The types of product being loaded determines the extent of fire protection warranted at a loading rack. Heavy oil loading would require less fire protection than a rack handling gasoline and doing switch loading.* The hazards associated with loading gasoline or other high vapor pressure products are greatly reduced when good bonding and grounding is introduced before loading hatches are opened. At least one minute

---

*Changing from one product to another.

should be allowed for static charge discharge before either spouts are withdrawn or load samples taken. When light products are loaded, the tank car soon becomes "too vapor rich" for ignition from static electrical charges. In any event a check should be made to see that an adequate number of fire extinguishers are provided--at least one every 100 feet with one at grade level at each end of the rack. In addition an adequate supply of water should be available with sufficient length of hose to reach all of the cars positioned at the loading rack. No part of the rack should be more than 100 feet away from a water supply source.

The Industrial Risk Insurers do in fact indicate that one or more of the following special protection system which employ fixed piping would be desirable at the loading rack.

a. Automatically actuated water spray system designed to immediately cover the entire rack area at a minimum density of .25 GPM/ sq. ft. (10.2 liters/m^2/min.).

b. Automatic foam-water system. This system would provide the fire blanketing effect of foam, and when the foam supply has been exhausted, it can continue to provide the cooling effect of water spray.

c. Automatic fixed dry chemical system. This type of special system can be installed where a fire water system is not available.

This system would provide the extinguishing effect of dry chemical, but does not provide the cooling effect of water spray. Furthermore, when its charge of extinguishing media is exhausted, it cannot be readily recharged to provide for continued operation in the event that a given fire is not extinguished by the initial charge.

All automatic systems should be provided with manual actuation stations, preferably two stations at widely separated locations and a minimum of 100 ft. (30.5 m) from the rack. It is also advisable to provide interconnections to shut down loading pumps and sound alarm systems upon operation of the special protection systems. When special protection systems are being planned, drainage and curbing in the loading rack area should receive special consideration.

It should be remembered that where overhead structures are provided over racks, many railroads demand a fixed clearance between the top of the car and the structure. Should the automatic fire extinguishing system project over the railroad cars, as it probably should, a check should be made with the servicing railroad to determine the desired clearance.

The actual filling procedure is frequently a manual operation whereby the loader may be filling more than one tank car at one time. The fill spouts will be inserted in the domes and the pumps started to fill the car. This is still a typical operation and considerable vapors are released to the atmosphere during the entire fill period. Meanwhile, the loader or fill rack attendent must pass back and forth on the rack especially during the "topping" period. Past evident of overfills provide evidence of the inefficiency of such an operation. These installations can be materially improved by vapor recovery loading arms, computerized fill control devices that measure the desired cargo load and automatically shut off the pumping system.

Another predominant spill source that duplicates leakage problems associated with tank truck telescopic loading arms is the trombone slide type arms when damaged. Loading rack attendents are prone to slap the loading arm into the fill dome. The action damages the ferrous metal arms and can eventually knock them ovate in shape. This in turn tears the packing in the sliding seal and extensive product leakage can occur. Repair will not correct the situation--expensive replacement of the arm section is required. A rack was viewed in one of the larger New Jersey refineries that had leakage from six loading arms that were in service. The rack operator completely ignored the situation and the plant engineer accompanying one of the authors on the survey also turned a "blind-eye" to the multiple leak sources. The situation was definitely of long duration; the earth under the rack was oil saturated, the pumps and piping also located under the rack were oil covered in a manner not conducive to good pump operation and the spillage definitely developed a fire hazard since a refined product rack was involved.

It can be stated that in lieu of conditions described, strict supervision is warranted to maintain desirable conditions in the loading/unloading area.

10. LOADING/UNLOADING PIERS (WATERFRONT FACILITIES)

10.1 Pier Design

Pier designs in excess of 15 years of age have become rapidly outdated. Wooden structures with spaces between the decking that permit the entry of drippings and minor spills into a waterway have little place in plants working toward spill-free operation. Additionally piers with wooden pilings have already been subjected to investigation by the US/EPA as water polluting sources themselves. Creosoted pilings have as much as 22 lb. of creosote pressured into each cubic foot of wood. When subjected to summer sun the exposed above water pilings can reach temperatures as high as 190°F. The built up pressure within the piling can result in creosote leakage which can infract the Federal regulation which prohibits generation and release of a sheen on the water surface. Creosote although an excellent protector of wood from marine worm attack has been characterized as an aromatic and marine pollutant and a pesticide. The use of creosoted pilings has not been banned and, to the knowledge of the writers, no enforcement actions have resulted from sheens developed by creosoted piling. The Federal government (USCG, USN, and USA) still use creosoted pilings for pier construction. Most alternative wood preservatives contain arsenic (between 22 percent to 45 percent) which has developed manufacturing problems that are being investigated by US/HEW National Institute of Occupational Safety and Health.

Newer loading/unloading piers are of concrete pile and deck construction. The actual pier is comparatively small in physical dimension servicing only the vessel's loading/unloading manifold and the access and egress companion-ladder. The actual mooring of the vessel, especially large tankers, are made to a spread of dolphins (clusters of piles) connected to the pier structure by metal catwalks.

The pier surfaces are curbed with controlled drainage. When desired rainwater can be drained by opening the restraining valve to gain flow. Contaminated water or oil spillage once contained by the curb can be drained to an onland sump tank which is later emptied into a tank truck for reclamation or nonpolluting disposal. To some extent this has eliminated the demand for catch trays to be positioned under pipeline connections. However, some facilities have retained catch trays which drain into the previously described sump tank. In this manner spillage from manhandling catch trays during the emptying process is eliminated.

10.2 Hose Handling

It is possible for hose handling to be engineered into a fingertip controlled process. Lifting and positioning of the hoses can be accurately handled through automated lifting and manipulating systems. The same system can be used for line cleaning (pigging) and valve opening and closing and line emptying through the inert gas method.

The dockman can also be provided with direct voice communication with the tank field and the deck crew of the vessel being serviced.

USCG regulations (CFR 33 Part 154.500) requires that each hose section be designed to have a minimum bursting pressure of 600 psi or more and a working pressure of 150 psi or more.

Each hose section must also be designated and marked to indicate the following:

1. The products for which the hose may be used or the words "oil service."
2. Date of manufacture.
3. Bursting Pressure.
4. Manufacturer's designed working pressure.
5. Date of last hydrostatic test

   (Note: The Federal regulation pertaining to hose test is very vague on the recommended frequency of testing for hose sections. The hydrostatic test pressure should, however, be 1.5 x maximum working pressure, as a minimum this would be 1.5 x 150 = 225 psi. Many plants, however, maintain their own blank flanges and hydrostatic testing pumps and examine and pressure test hoses semi-annually.)

6. The pressure used for that test.

The exception to marking the hose involves maintaining test records that can be associated with each hose--specifically marking hoses so that each section can be identified with the maintenance record.

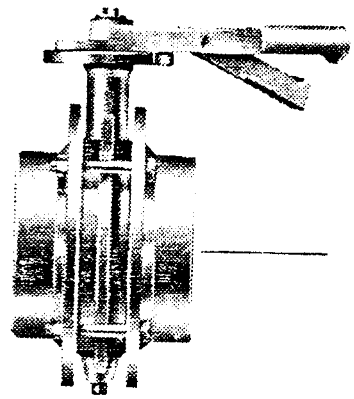
Chaffing gear should be used with each hose section to which a lifting sling is attached. This will protect the hose from being cut by the steel sling and from abrasion during the movement of the hose during the pumping action. The hose should have sufficient slack in its length to compensate for ship movement. However, if the hose is rested on a ship's stanchion or bulwark, it should also be protected from chaffing action.

10.2.1 Making and Breaking Hose Connections

This is a prime time for minor spills generally caught in catch trays, usually the lower half of a cut-off 55 gallon drum. It is difficult for the hose handlers to raise the end of the hose rapidly enough to contain product that remains in the hose after a loading or unloading procedure. Some industrial locations have overcome the spillage problem by attaching butterfly valves. Hereto industry was reluctant to use this positive type closure valve on flexible hose lines due to added weight. Complaints were made that "they stick" and "are hard to open" after closing. To a large extent modern engineering has eliminated most of the problems associated with their use. Butterfly valves are available in most sizes up to 48 in. diameter. Figure 10-1 depicts the external and internal workings of the valve. Industrial practice is to install a butterfly valve on the final flange of the flexible hose line, then to add an additional spool piece to the most offshore side of the valve. The spool is then connected to the shipboard loading/offloading manifold at deck level. From the spool is attached a drain line which can be directed to the tanker's cargo compartment or into a suitable container. At cessation of a product transfer, the flow control valve on the ship's manifold is closed as is the butterfly valve. This leaves a limited quantity of oil in the spool piece which can be drained back into the tanker or into the previously described waste oil container prior to breaking the shipboard connection. Figure 10-2 shows the valving, spool piece and drain arrangement.

10.3 Marine Loading Arms

A number of organizations such as FMC Corporation, Brea, California and Continental Emsco, Dallas, Texas manufacture marine loading systems that eliminate the need for flexible hose lines. These hydraulically powered, all metal arms for loading and unloading liquid cargo have been increasing in number since introduced in 1956. They do reduce the possibility of massive spills that have occurred in the past due to ruptured hose lines. The manufacturers claim they reduce labor costs, dock clutter, and expedite loading/unloading operations. The



External View

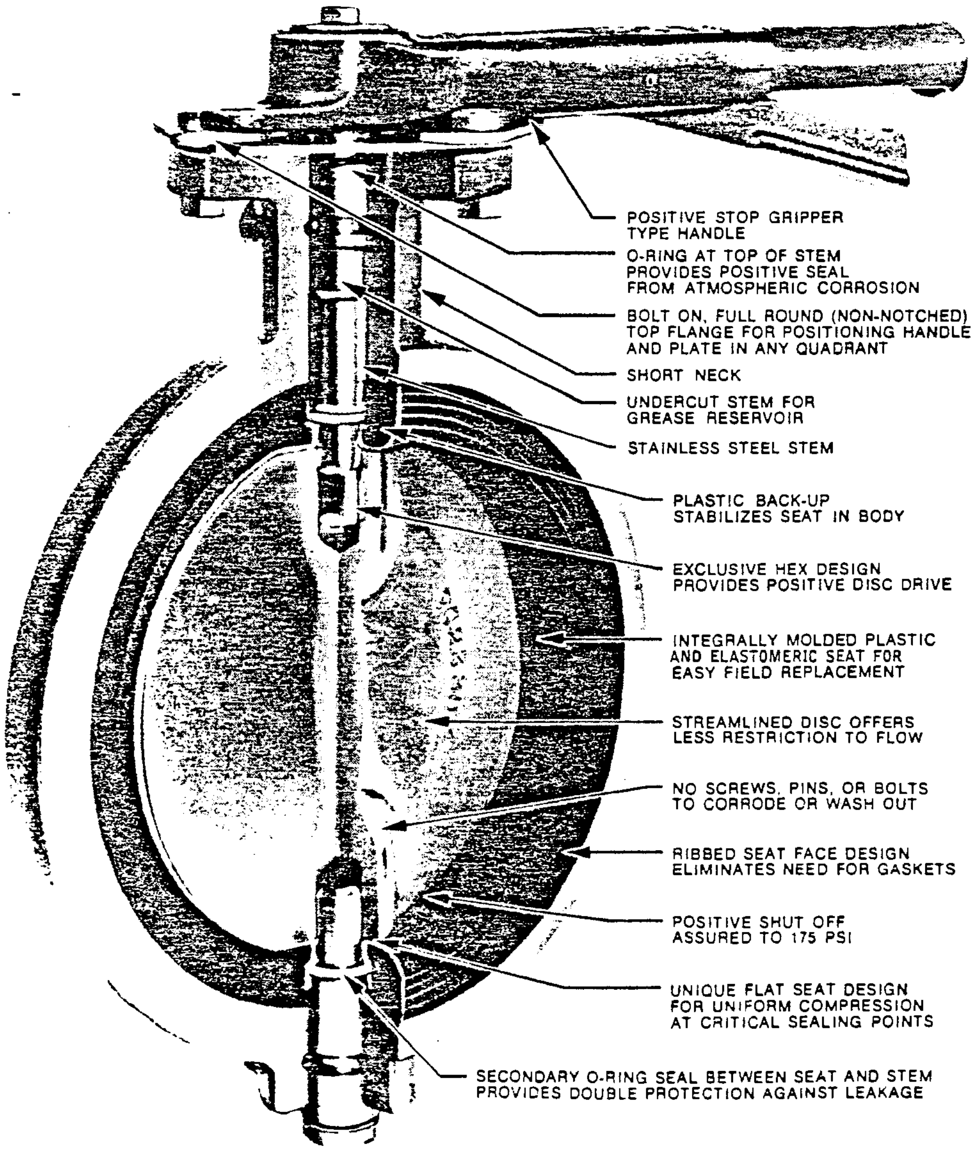


FIGURE 10-1.

Internal View

WECO BUTTERFLY VALVE
(Illustration - FMC Corporation)

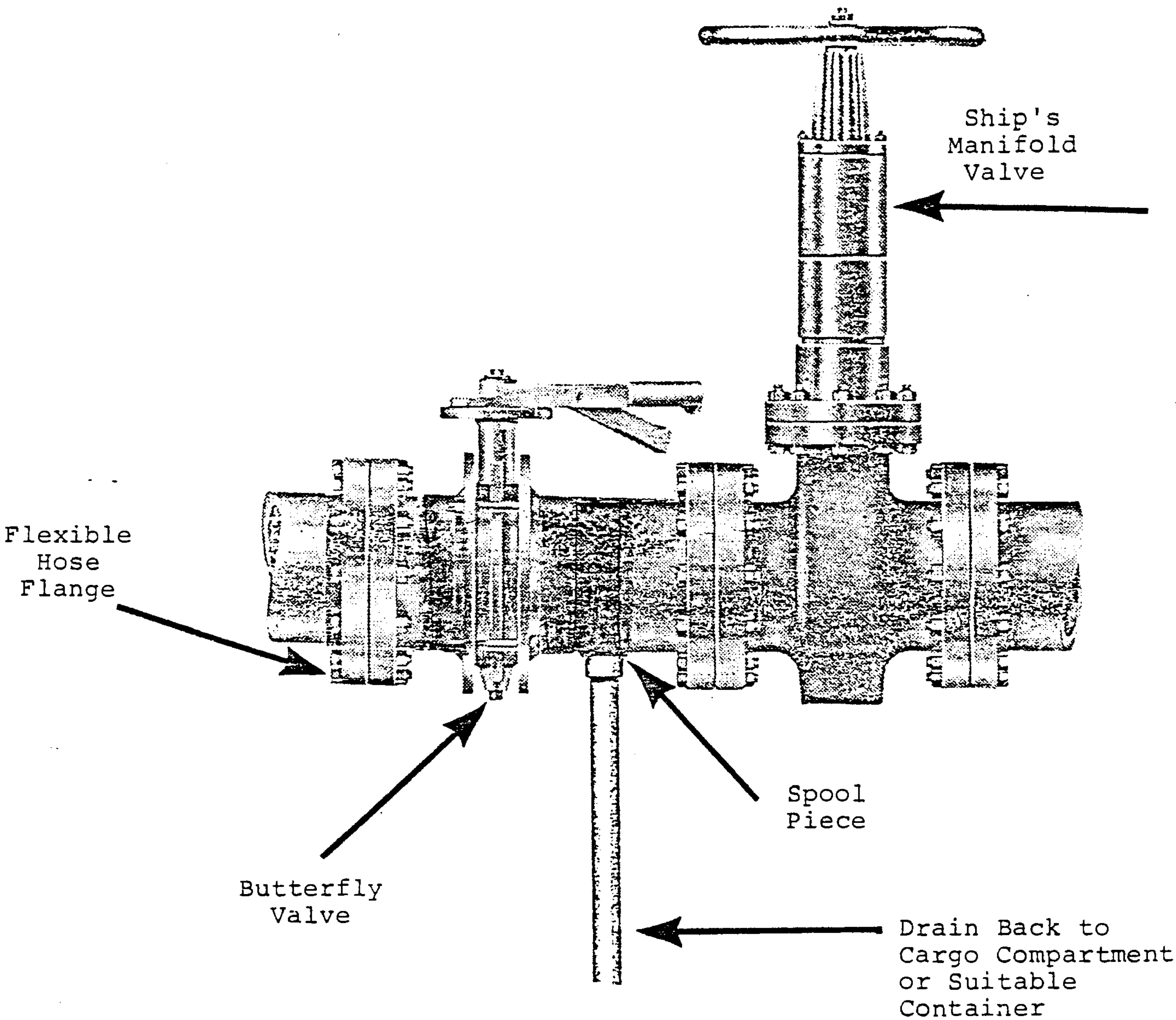


FIGURE 10-2.

Typical Butterfly Valve
Installation

arms are available from small single arm manually operated units for barge handling to multiple bank, 24 in. hydraulically operated systems capable of transferring 90,000 barrels of liquid per hour per arm.

The arms are self-adjusting once connected to the ship's flanges and will follow all movements of the ship as it rises and falls with the tide, wave action and draft changes. Alarms are provided to warn operators when the maximum drift limits are being approached.

The Continental-Emsco loading arm is controlled from a central control console. The console is equipped with a selector valve that assigns the three control valves (inboard arm, outboard arm and traverse) to a specific station. Two hydraulic motors, driving through speed reducers, control the boom's vertical movement. An identical drive package actuates the rotating counterbalance which in turn actuates the ouboard arm through a cable belt. Traverse motion is supplied by two hydraulic cylinders that are mounted on the trunion assembly. Hydraulic power is supplied by an explosion proof electric motor-driven pump mounted on the reservoir tank.

By operation of the three directional control valves, the arm unit can be made to extend, retract or traverse. The operator maintains positive control at all times as the arm is maneuvered into position.

Once the hook-up is made, the hydraulic control is switched into neutral and the arm can then follow the movements of the ship. Any sudden surge of the ship before the arm is in free-wheeling will cause the arm to override the controls.

Should a power failure occur while positioning the arm for hook-up, the counterbalance of the unit prevents violent motion of the inboard and outboard pipe sections.

Hydraulically actuated jaws engage the back face of the tanker's manifold flanges, and clamp the face of the flange against the loading arm flange. This option eliminates flange bolting at the ship's manifold. In case of emergency, the quick disconnect coupler may be immediately released from the deck manifold at the remote control station. No personnel are necessary on deck at the manifold to assist in the disconnect.

Continental-Emsco offers a radio remote controlled marine loading arm. This system is operated entirely from the tanker's deck where the operator has full control of all vertical and horizontal movements of the arms. Arms move on signal from a portable transmitter held by the operator. There are no cables connecting the radio transmitter to the loading arm, so that the operator can move anywhere on deck, freely, without restriction.

With this combination it is possible to connect or disconnect marine loading arms by radio control without using any hand tools. The arms use a minimum of dock space and installation is simple requiring only bolting down the base plate to the dock manifold.

Another safety factor at some locations is to divert the passage of tanker crews clear of the operating area. A separate fenced passageway restricts crew members passed the dock operating area without the need to actually enter the loading/unloading zone.

10.4 Operations Manuals

Under Federal law each waterfront facility must develop and submit to the U.S. Coast Guard an operation manual that describes:

1. The equipment and procedures used to meet operating rules.
2. An outline of the duties and responsibilities of personnel involved in oil transfer operations.
3. A map and description of the geographical location and a physical description, including a plan that show mooring areas, transfer locations, control stations and storage locations of safety equipment.
4. Operational hours, sizes, types, and number of vessels that can transfer oil simultaneously.
5. A list of other products that may be handled at the facility that may be incompatible with oil.

6. The minimum number of persons on duty during transfer operations and a description of their duties.
7. Names and telephone number of Federal and industrial personnel which will be called by the facility in the event of an emergency.
8. The duties of watchmen required by law to guard or protect unmanned vessels in the facility.
9. A description of each communication system at the facility.
10. The location and description of personnel shelters on the property.
11. A description of drip and discharge collection and vessel slop reception facilities if any.
12. A description of emergency shutdown systems and their location.
13. Quantity and type, location and use techniques of spill response containment equipment.
14. Maximum relief valve setting or if relief valves are not provided, the maximum system pressure of each oil transfer system.

15. Procedures for:

    - Loading arm operation and limitations of same
    - Oil transfer
    - Completion of pumping
    - Emergencies
    - Contingency plan reporting and containing oil discharges

16. A brief summary of Federal, state, and local oil pollution laws and regulations.

17. A description of training and qualifying persons in charge of oil transfer operations.

Many organizations have introduced a system of supernumerary loading and offloading. A specially assigned person, preferably a retired deck officer, supervises the transfer procedure. This individual inspects (checklists are desirable) all equipment aboard the tanker and on the loading dock prior to transfer line connection. Having had marine experience he also approves the mooring lines and the method of mooring. The supernumerary also checks and approves the ship's spill response equipment and cargo papers. He verifies readiness for cargo discharge with the ship's captain and the shoreside personnel and authorizes the start of pumping operations.

At the end of the pumping operation the supernumerary supervises the disconnect and hose storage procedures. By this failsafe type of operation a number of plants that had developed a reputation of "chronic pollutors" have begun to operate as a spill-free operation.

11. SPILL DETECTION SYSTEMS ON WATER

11.1 General

National oil spill statistics indicate that accidental spills frequently occur during hours of darkness when it is difficult to detect oil on water and/or during weekends when plant facilities have a limited number of on-duty plant personnel. The spillage and leakage of oil and oil products occurs predominately at marine terminals during oil loading/unloading operations when workers and tanker personnel are involved with making and breaking flange connections, raising and lowering flexible hose lines, opening and closing valves, metering flow rates, checking tank or cargo compartment oil levels, or handling mooring lines.

To reduce lost products, costly response actions, expensive fines, and resulting pollution, spill detection systems can be cost beneficial.

Spill detection systems placed in effluent discharge areas or in a waterbody in proximity to a loading/unloading dock can alert plant operators of spillage which may occur and go undetected for a lengthy period of time.

Most systems utilize combination visual and/or audible alarms that facilitate an early response action to contain and otherwise mitigate a spill.

A number of major petroleum refineries and manufacturing plants in the United States, Canada and the Carribbean have installed electro-optical monitors which permit automatic, continuous remote oil spill detection without water contact or sampling by sensing only a single point on the surface of a moving body of water. This type of spill detection system, the infrared oil film monitor, was developed in 1972 and was extensively tested by the U. S. Coast Guard in both laboratory and field environments.

The infrared oil film monitor is sensitive to oil concentrations of less than one part per million (ppm) in turbulent wastewater streams and it can detect even smaller concentrations of oil in calm water. The exact concentration in parts per million is somewhat meaningless because of the uneven distribution of oil within the water column. Tests have shown that one milliliter of oil spread evenly over 10 square meters (109 square feet) of water results in a 0.1 micrometer film. Even with extreme turbulence and entrainment, sufficient oil always rises to the surface, hence triggering an alarm.

Water surface monitoring is responsive to the Federal Water Pollution Control Act where prohibitions are described in terms of appearance: oil discharges must not ". . . cause a film or sheen upon or discoloration of the surface of the water. . ." The effluent regulations for the National Pollutant Discharge Eliminiation System (NPDES) limits oil concentrations to 15 ppm on water. On this basis, the correlation of surface appearance and film thickness with volume measurements becomes extremely difficult.

Spill detection monitors are currently employed in a number of commercial applications. The following installations, extracted verbatim from the "1977 Oil Spill Conference Proceedings, New Orleans, Louisiana," illustrate applications of oil detection based on monitoring a single point at the surface of the water column.

- ". . .At a large east coast petroleum refinery. Here remote oil monitoring instruments are mounted over five separate cooling water streams. Several of the monitored streams are in open concrete troughs while others are in buried sewer pipes. Explosion-proof infrared oil film monitors are installed on catwalks and in manhole covers from five to 15 feet above the streams. Average flow rates range from 0.5 to five feet per second. Instrument locations were chosen so that the oil spill detector could pinpoint condenser coil leaks by isolating the section of the refinery served by a particular cooling water stream. Maximum sensitivity is assured with special short time constant response circuits. The instruments responds to oil slicks approximately six inches in diameter passing at a five foot per second flow rate.

Monitor outputs are recorded by a paper chart recorder. Additional alarm circuitry causes a master alarm to be activated when the oil alarm rate exceeds a certain predetermined value (e.g., 10 alarms per hour) or when the duration of a single oil alarm exceeds a certain time limit (e.g., 20 seconds). Process water may be diverted to a holding pond or, if necessary, a section of the refinery operation can be shut down when a major leak is detected. In this application, the instruments function essentially as an early warning system by locating small leaks and thus preventing costly ruptures and product losses. . ."

- ". . .Monitoring refinery effluent in the Carribbean. Other remote oil detection instruments are used in the Caribbean to monitor refinery effluent immediately prior to discharge into a harbor. In this application, the effluent is a combination of treated ballast water from oil tankers and refinery process water which has been routed through a series of separators and filters. An infrared oil film monitor is mounted over a culvert where discharge water is channeled under a road and then into the sea. The instrument monitors an eight-inch spot in the middle of a 20-foot wide stream. Operating height is approximately 10 feet above the water surface and the stream velocity is roughly two feet per second. Experience in this application has shown that the single point monitored in the center of the stream was respresentative of the surface of the entire stream from bank to bank. Scanning across the stream originally was considered by refinery personnel but found to be unnecessary. One monitor has operated continuously at this tropical installation for more than six months with no maintenance or cleaning, despite average daily temperatures in excess of $85^{o}F$ and an extremely dusty atmosphere. The instrument's signals are transmitted by telephone wires to a control room about 1,000 feet from the outflow. Here an oil spill alarm is displayed by a red light and buzzer. In the event of a major oil spill, a containment boom can be released where the outflow enters the harbor. In this application, the monitors function as a last defense against oiled beaches in a highly popular tourist area. . ."

- ". . .At a manufacturing plant in Pennsylvania. A remote oil detection instrument has been installed inside an underground cavern where there is a series of chambers that once served as sand filters for a municipal water supply. These chambers have been emptied and now are used as holding tanks for both process water and storm water runoff. The sensing instrument, because of its non-critical alignment and automatic gain control, is able to adjust to variations in water level within the cavern. The mean water level is four feet below the instrument, and the flow rate is approximately 0.1 feet per second.

The underground chambers function as gravity separators allowing the water to flow through while any oil present floats on the top and triggers the infrared oil film monitor. The instrument's output is continuously monitored and, when a constant oil alarm has been recorded for a preset time, a vacuum pump is used to remove the oil accumulated on the water surface. If the caverns were not monitored, the capacity of the separators could be exceeded, resulting in oil spilling into a river which supplies drinking water for several communities downstream. . ."

- ". . .At a Canadian refinery. An infrared reflectance monitor was installed in a manhole and used to detect oil spills in an ostensibly clean sewer line which empties into the Saint Lawrence River. The manhole cover was removed and the instrument installed at ground level. The sewer pipe is four feet in diameter and the flow rate is approximately five feet per second; a ladder in the manhole creates an extremely turbulent water surface nine feet below the instrument.

In tests conducted by instrumentation engineers at the refinery various types of oil were introduced into the monitored sewer line at carefully calibrated rates from 1,000 to 5,000 feet upstream of the instrument. Both heavy and light hydrocarbons in concentrations ranging from 1 ppm to 15 ppm were reliably detected and recorded by the infrared oil film monitor. In this application, the instrument is used as a continuous effluent monitor to demonstrate compliance with discharge regulations. The outfall is periodically checked by Environment Canada.

There are many more applications of spill detection systems throughout industry. The following section is devoted to the current manufacturers, suppliers, and operational characteristics of oil monitoring systems.

11.2 Manufacturers and General Suppliers of Oil Monitoring Systems

AQUALERT MODEL - 240

Manufacturer

Bull and Roberts, Inc.
785 Central Avenue
Murray Hill, NJ 07974
(201)464-6500

Operational Characteristics

Range - Heavy Oil 0-50 ppm

Light Oil 0-100 ppm

Accuracy - 5% full scale (standard application)

Repeatability - 2%

Operates with less than 1% light transmission

Ambient Temperature - 32°F to 140°F

Lamp Life - 5,000 hours

The Aqualert Model-240 is an in-line, continuous, oil detector, pollution monitor. Instrument operation is based on the measurement of light transmission through the fluid being monitored and its potential contaminant. The measured value of the transmitted light is used as an index of sample stream contamination. Two segments of light spectrum are monitored. The first is an ultraviolet wavelength which is selectively absorbed by organic materials. The second is the visible light portion of the lamp output, used as a reference which compensates for the presence of light absorbent materials that are not specific absorbers in the UV wavelength. Absorption depends on the absorption coefficient of the material. The reading is compared with a curve for a specific contaminant and indicates the contaminant concentration. A sketch of this device is shown in Figure 11-1.

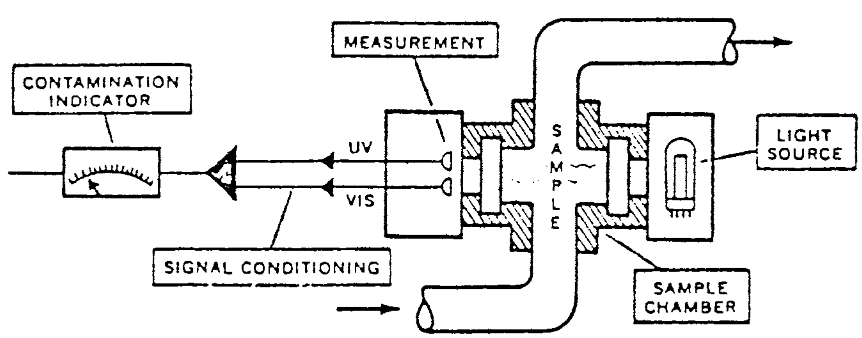


FIGURE 11-1. AQUALERT Model-240

Cost:

1) Aqualert Oil Detection System consisting of the following:

1 Aqualert Model 240 Control Box

1 Sample Assembly consisting of:

a) sensor enclosure

b) flow chamber, 1/2" NPT x 2" viewing depth

c) u.v. lamp enclosure

1 - 10 ft. sensor wire or cable (2SWA-43)

2 Instruction manuals

BASIC SYSTEM TOTAL	$4,160.00

2) Flow chamber, 1/2" NPT x 6" viewing depth for increased sensitivity (in addition to above price).	300.00

The following accessories depend upon specifications:

1)	Two 1/4" solenoid valves for stem cleaning	154.70
2)	1.2" sample flow indicator	137.90
3)	Cooling Coil (if sample temp. exceeds 125°F.)	305.00
4)	Audible Alarm	60.00
5)	Recommended Spare Parts	129.80
6)	Additional sensor wire	.60/ft.
7)	Additional sensor cable	2.30/ft.
8)	Additional instruction manuals (standard)	20.00/ea.
9)	Set vendor drawings (standard)	10.00/set
10)	Set vendor drawings (standard)	20.00/set
11)	Services by our engineers available as per service policy #Po-79-51	
12)	Explosion proof, NEMA class, and specially designed systems available upon request.	

OIL-IN-WATER ANALYSIS SYSTEM

Manufacturer

Teledyne Analytical Instruments
333 West Mission Drive
San Gabriel, CA 91776
(213)283-7181

Operational Characteristics

The TAI oil-in-water analysis system is a dual wavelength ultra-violet analyzer combined with an essential sample conditioning system. The dual beam analyzer employs a reference signal at a wavelength of 4,000 Angstroms at which oil does not absorb. Although the reference signal is affected by turbidity, as is the measuring signal (2,540 Angstroms), electronic circuitry within the unit compensates by comparing the two signals and ratioing turbidity to zero. The unit functions as the sample is fed into both sides of a conditioning system for sample preparation. A high-speed, high-sheer homogenizer disperses any oil in the sample, including small and large oil droplets, and oil adsorbed onto foreign matter. A portion of the stream is conditioned to remove all oil (dissolved and undissolved) without altering the background (organic or inorganic non-oil compounds). The analyzer then substracts the background from the total and reads the contribution of oil only. The analyzer is calibrated with a known standard on a one-time basis. Figure 11-2 is a sketch of the system.

The unit can be used continuously or intermittently to gain an accurate analysis ($\pm$1%) of oil in an effluent stream discharges. The samples are drawn from both sides. A continuous record of oil

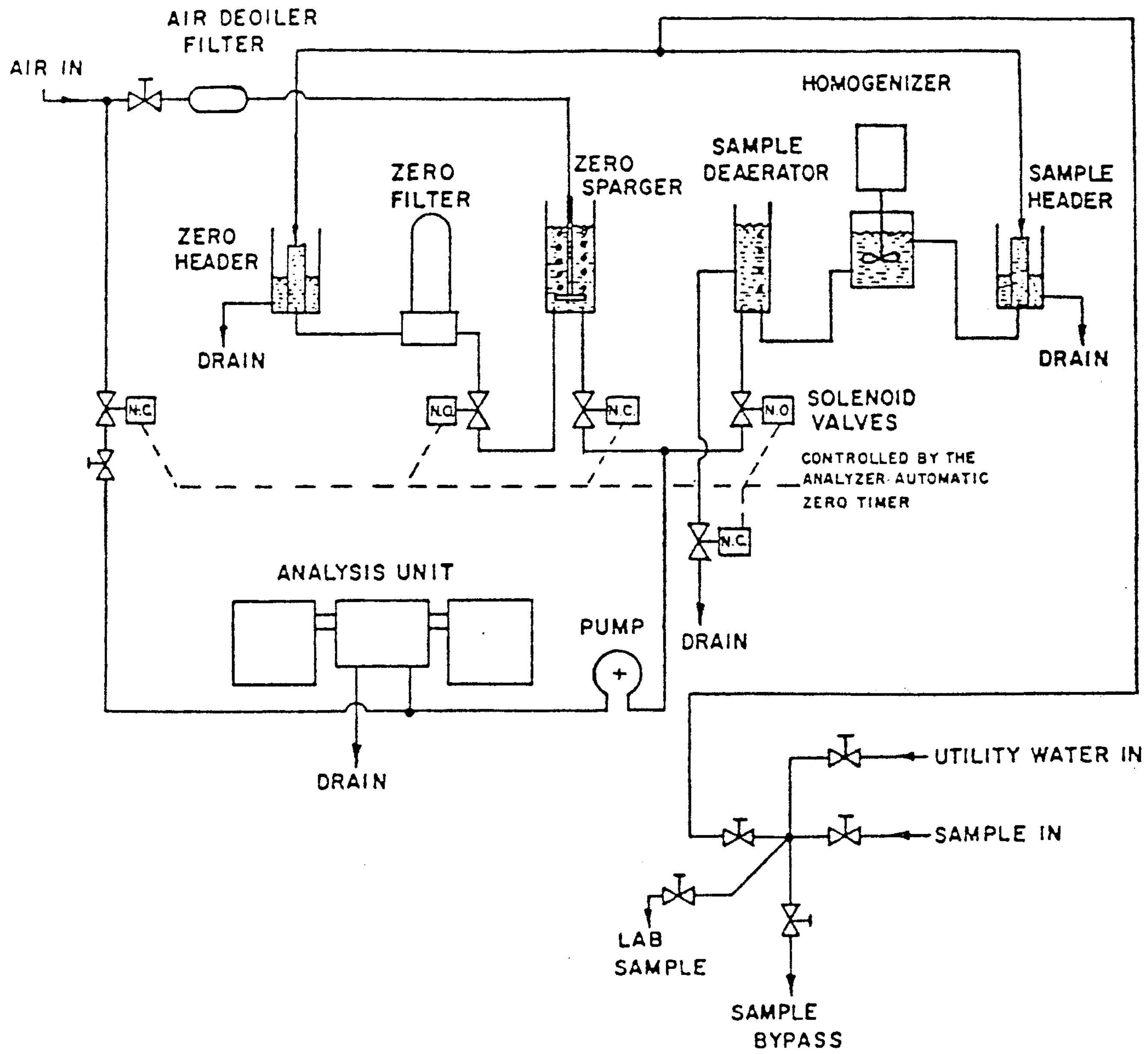


FIGURE 11-2. TELEDYNE'S OIL IN WATER ANALYSIS SYSTEM

content is obtained and relays are provided that would permit the use of an alarm system such as a light, bell or siren. The cubicle provides shielding against cold weather and human interference factors.

Cost:

The base price of a standard unit Model 661C is $10,530 whereas an explosion proof unit, Model L660C, adaptable for industry which handles flammable liquids is $12,030.

INFRARED OIL FILM MONITOR

Manufacturer

Wright and Wright, Inc.
P.O. Box 1728
Oak Bluffs, MA 02557
(617)693-2608

Operational Characteristics

This monitor was developed under USCG sponsorship. It utilizes infrared reflectance at the 3 micron water molecule resonance band to detect floating oil slicks. The instrument consists of a transmitter and a receiver in rugged, cast aluminum housings which are mounted above the water to be monitored. The transmitter projects a light beam to the water surface and the reflected infrared light is analyzed by the receiver. An alarm is activated when oil is detected. If desired, instrument response time can be adjusted to ignore small slicks.

Once installed the system can provide continuous spill detection under any weather conditions. Since the unit, or any of its components does not make physical contact with the water, it is not susceptible to marine fouling or impact damage. It can be mounted on a piling, pier, bridge, or small craft bow with the sheen detection instruments mounted from six to 30 ft. above the water. One model is available for use at heights in excess of 30 ft. and explosion proof housings can be provided.

An auxiliary piece of equipment, the "Remote Readout Unit," is available. This unit is cabinet mounted and is connected by cable to the Infrared Oil Film Monitor. It is designed to permit the Infrared Oil Film Monitor to activate automatically remote control equipment (e.g. motors, solenoids, skimmer, etc.). With the Remote Readout Unit, a technician at a remote location can observe the status of the Infrared Oil Film Monitor and the water surface below it.

The Remote Readout Unit incorporates the following features:

1. A red lamp (OIL ALARM) to indicate that the instrument has detected an oil film. This lamp is normally off and lights when an oil slick is within the instrument field-of-view. The lamp goes off when the slick has passed.
2. A loud audible alarm sounds when the red lamp (OIL ALARM) is on. The audible alarm can be switched off, if desired.
3. A DPDT relay (with each contact rated at 10 Amps, 115 VAC) is activated when the red lamp (OIL ALARM) is on. This relay can be used to activate remote control equipment when oil is detected.

4. An analog meter readout of the signal processing circuitry of the Infrared Oil Film Monitor.

   Low meter reading - clean water (no oil)

   High meter reading - oil on water

5. A green lamp (INSTRUMENT STATUS) to indicate that the Infrared Oil Film Monitor is operating properly. This lamp is normally on and goes off only when a component failure has occurred within the instrument. The Infrared Oil Film Monitor has been designed for at least six months continuous unattended operation with no maintenance required during this period.

6. Built-in logic to prevent OIL ALARM from activating when INSTRUMENT STATUS lamp is not on.

The following comments and sketch describe and depict a typical Wright and Wright, Inc. installation.

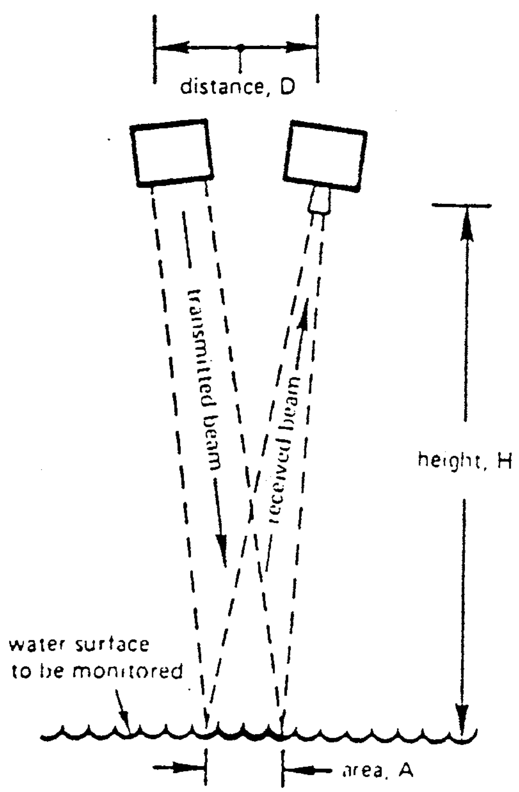


FIGURE 11-3. INFRARED OIL FILM MONITOR INSTALLATION

The Infrared Oil Film Monitor is mounted 6 to 30 feet (H) above the water directly above the water surface to be monitored (A) normally one square foot of water surface. The transmitter and receiver are less than 1 foot apart (D) and the tilt angles are within ±1% off vertical. Above average tidal ranges of 8 to 10 feet will have no effect on this instrument since it is equipped with an automatic gain control that is activated by any weakening of the signal.

Cost: (7/80)

Infrared Oil Film Monitor, in explosion-proof housing	
Model D500	$9,500.00*
Approved by Factory Mutual for Class I, Div. 2, Group D hazardous locations, Temp. Class T1	
Model D250	9,500.00
Approved by Factory Mutual for Class I, Div. 1, Group D hazardous locations, Temp. Class T2D	
Model D150	9,500.00
Approved by Factory Mutual for Class I, Div. 1, Group D hazardous locations, Temp. Class T3C	
Additional transmittters for Models D500, D250 or D150	1,609.00
Infrared Oil Film Monitor, Model E250	4,900.00

*Prices are in U.S. dollars, F.O.B. Oak Bluffs, Massachusettts, and do not include applicable taxes, duties, insurance and other shipping charges. Prices are subject to change without notice. All sales are subject to Wright & Wright, Inc.'s Standard Terms and Conditions of Sale.

Additional transmitter, Model FL250 in floodlight housing	$ 331.00
Film Thickness Discriminator Option	285.00
Selectable Criteria Alarm Option	
when specified with new instrument	705.00
when purchased separately	1,230.00
Remote Readout Unit	
Model R2, for rack mounting	1,140.00
Model R3, for rack mounting, with paper chart recorder	1,620.00
Custom Housings and Systems	Contact factory
For Delivery Information	Contact factory

D-O-W (DISPERSED OIL-IN-WATER) MONITOR

Manufacturer

C-E Invalco
Division of Combustion-Engineering, Inc.
P.O. Box 556
Tulsa, OK
(918)932-5671

Operational Characteristics

The Dispersed Oil-In-Water (D-O-W) Monitor provides continuous on-line monitoring of effluent streams, detecting oil in water normally in a range of 0 to 150 ppm, with accuracy of $\pm$5.0%. The monitor operates effectively to temperatures up to 175^{o}F, and working pressures of 60 psig.

The monitor utilizes a dual beam light measuring system which continuously probes the rate of ultraviolet absorption in the discharge stream. Clear water transmits ultraviolet (UV) with very little absorption whereas most petroleum oils and their derivatives absorb UV either partially or completely. Thus, variations in absorption provide a sensitive and accurate means for the determination of oil contained in water.

Output from the system is displayed on an indicating meter or an operational chart recorder. Audible and visible alarms could be incorporated in the system.

Power requirements: 95-130 VAC, single phase 60 Hz, 60 watts

Input range (crude, fuel and lube oils): 0-20 or 0-150 ppm

Maximum Fluid Temperature: 175°F

Ambient Temperature: 40°F to 150°F

Maximum Pressure of Detector Cell: 60 psig working, 100 psig test

Nominal Sample Flow Rate: 1 gpm

Pressure Drop at 1 gpm: 10 psig

Pressure Drop at 1 gpm with static mixer: 20 psig

Detector Cell Connections: 1/4" NPT inlet and outlet

Connections Required in Main Stream Piping: 1" NPT

For use at a loading/unloading pier, the incorporation of a small pump would be required to draw a continuous water sample from the dock area and feed the sample into the monitoring system.

Cost:

The base price of this unit with no housing is $6,273.72; with weatherproof housing, $6,611.76; and with explosion proof housing, $8,314.92. About two weeks lead time can be anticipated following an order.

OIL SENSOR MONITORS

Manufacturer

Rambie, Inc.
Irving Business Park
1100 E. Airport Fwy.
Irving, TX 75061
(214)438-6909

Operational Characteristics

These active infrared sensors illuminate the water, then spectrally analyze the reflected infrared energy for the presence of floating hydrocarbons. When a hydrocarbon is indicated, the alarm system is activated with a relay closure. The user selected time delays discriminate between persistent large spills and short period smaller spills.

The sensors are mounted remote from the water and operate in the extremes of tropic and arctic marine environments. They are seldom affected by waves, water level changes or floating debris. False alarms from other infrared sources such as the sun, lights and emission from the water are completely eliminated. They continuously test themselves for faults.

The Oil Spotter OS 20 is housed in a single 11-pound cylindrical container; and it is mounted directly above a point on the water that is to be monitored. The unit is simple to install, operate, and test (without spilling oil).

Should an explosion hazard be present, the Oil Spotter can be housed in an explosion-proof junction box. In this housing the sensor becomes known as the Oil Spotter OS 25.

The Sensor uses a transmitter mounted on a tower and a receiver located across a body of water on a second tower. The receiver and transmitter can be scanned to monitor an extended line between the two towers. The power supply, mounted near ground level, is housed in an explosion-proof box. The receiver and transmitter are normally mounted 20 or more feet above the ground, which according to the manufacturer precludes the need for explosion proofing at hazardous locations.

Although the device was originally designed for monitoring a water surface, it is equally useful to monitor a solid surface such as soil or concrete. They will warn when either water or liquid hydrocarbons cover the monitored solid surface.

Cost:

The Oil Spotter is priced at $4,780. (When housed in an explosion-proof case the cost increases to $6,190.). The Scanning Oil Sensor costs $19,500. These prices are FOB Irving, Texas and the terms for payment are net 30 days after delivery.

OIL SPILL DETECTION SYSTEM

Manufacturer

Versatile Environmental Products
60 Riverside Drive
N. Vancouver, BC
Canada V7H1T4
(604) 929-5451

Operational Characteristics

- Detector/Transmitter

The oil detection element is constructed in the form of a loop from a porous oleophilic material. Two pieces of the material are butt joined using an oil soluble, water insoluble adhesive. In the presence of hydrocarbons, the joint parts separate thus permitting the sensing tube to drop and initiate the transmission of the detector signal. The detector element will part within a few seconds of oil contact in the case of #2 or light oil and within one minute in the case of #5 oil or equivalent. Higher viscosity oils have difficulty in penetrating the element and as a result, the unit is not recommended for such oils. The element is replaced by the use of two ball lock pins. Adjustment of the joint line to just above the water level is easily performed.

Each positioned buoy is identified with a three digit number with the first digit identifying its group. Prior to shipping, this number is set into the telemetry system of the transmitter permitting its identification by the receiver. Once the sensing tube has tripped the magnetic switch, the telemetry system and transmitter are automatically turned on. At that time, a double series of coded, two tone frequency shift keyed signals are transmitted. To ensure reception of the signal, it is repeated after twenty seconds and every minute thereafter. The system provides a high degree of security and permits reception even in the presence of other transmissions.

Because the security of the system is considered to be extremely important, a battery level check is provided. Should the battery voltage drop below the required operating level, the transmitter will initiate a separate signal. This results in a flashing visual display and the lighting of the 'Low Battery' indicator on the receiver.

To ensure water tightness, an air valve is installed which permits pressurizing of the transmitter capsule and checking for leakage. To minimize damage to seals, the unit has been designed to be charged through the antenna. Similarly, an 'On-Off' switch is provided which is activated by a magnet mounted in a plastic holder, screwed into a blind hole on the top of the transmitter capsule.

- Detector/Receiver

Each receiver is coded to accept signals from a group of monitoring buoys. Upon receiving a signal from a buoy, the receiver automatically scans the message for accuracy and coding. Should the incoming signal match the group coding of the receiver, the oil spill indicator light is illuminated, and the external alarm contacts close. Subsequent signals are displayed as they arrive with the preceding signals being moved into the storage register. Messages stored are shown by indicator lights which are numbered from one to four. Pushing the 'Cancel' button permits the recall of the preceding messages. This memory feature allows more than one buoy to signal into the receiver without loss of a message and permits determination of the size or direction of travel of a spill when a number of buoys are being used.

When incoming signals are not coded to match the receiver coding the signal is ignored. When the signal approximates the receiver coding but contains a data error, which is determined by the receiver logic, the buoy number is displayed in a flashing mode and the 'Data Error' indicator is illuminated but the external alarm contact will not close.

The receiver is not fitted with an 'On-Off' switch in order to prevent the inadvertent shutting down of the receiving system. A small light appearing in the upper display window indicates 'Power On'. To ensure that all lights are operational, a 'Lamp Test' button is provided. Should it be desired to listen to the channel of the system in operation, the 'Audio Test' button may be pressed and locked into position. When the 'Audio Test' button is released, all background noise is filtered out and the distinctive noise of the frequency shift keyed (FSK) signal is heard. This may be turned off by pressing the 'Audio-Off' button.

An antenna is provided for use with the receiver. In some instances, it may be preferred to use a remote antenna, which has proven to be satisfactory.

The power input is normally set for 110 volts AC with a normal draw of 1/10 ampere. When desired, the receiver can be provided with a 220 volt AC connection. One receiver can run up to 99 transmitters if necessary.

Cost:

The base price of the unit is as follows:

Oil spill detection transmitter	-	$2,000.00
Oil spill detection receiver	-	2,000.00

F.O.B. Vancouver, B.C.

NOTE: 15% import duty applicable for deliveries within USA.

OIL DETECTION SYSTEM

Manufacturer

Spectrogram Corporation
385 State Street
North Haven, CT 06473
(203)281-0122

Operational Characteristics

The system operates on the principle of petroleum products exhibiting a fluorescent characteristic when subjected to high energy activation. When an oil sample is irradiated with high energy emission such as short wavelength ultraviolet or x-ray energy, the sample will absorb a portion of the excitation energy and reradiate lower energy of a longer wavelength such as visible light. Since both the wavelength of maximum energy absorption and the wavelength of reradiated energy are a function of the molecular composition of the oil, the oil detection buoy provides an alarm signal upon the detection and identification of a specific oil type.

The basic system consists of a land station, three buoys (two simultaneously operational, one stand-by) and the interconnecting cables. The land station or main console contains the power supplies, strip chart recorders and the alert/alarm logic circuitry. Each buoy contains an excitation energy source, a multi-channel optical detection system, solid state detectors, integrated circuit photometric amplifiers and logic circuitry, and various local power supplies. The buoys derive operating power from the main console via the interconnecting cable. This waterproof cable also carries the necessary data signals from the buoys to the console recorders and the alert/alarm network thus providing final contact closures for external and remote indications such as lights, audible alarms, or the "shut-down" of the transfer pumping system.

The units have had a 12-month test period under varying weather conditions. One system was installed at a tidal river location, and the second at a barge loading/unloading dock.

The basic system typically included three oil detection buoys, one land based recorder/power console, and the required interconnecting waterproof cable.

Spectrogram Corporation has recently stated that under contract with the United States Coast Guard, the land console via five wire waterproof cable has been updated with a free floating buoy system using solar cell battery recharge panels. This modification requires no cable to land and all data communication is done by radio frequency telemetry.

Cost:

These new buoys are priced at $4,500-5,000 each. The computerized land base station is priced at $15,000. A system consisting of three buoys and a computerized base station has a selling price of $30,000. Delivery is nominally 90 days and the costs are FOB North Haven, Connecticut.

MULTISPECTRAL ACTIVE/PASSIVE SCANNER

(Fluorescence Oil Spill Detector)

Manufacturer

Baird-Atomic, Inc.
125 Middlesex Turnpike
Bedford, MA 01730
(617)276-6140

Operating Characteristics

The oil sensor projects a beam of ultra-violet radiation and simultaneously observes the fluorescence emitted by oil on water. To overcome the effects of varying range, natural sea fluorescence, atmospheric conditions, and lamp aging, the ratio (rather than the amplitude) of the observed fluorescence in two spectral regions is used to determine the presence and type of oil.

Recent tests indicate a maximum useful range of 600 feet at night and 30 feet in daylight with 6 month lamp life. A range of 900 feet has been achieved, but with a lamp life of 4 hours continuous use.

- Dimensions and Operating Demands

Head - 24" W x 30" D x 12" H, 95 pounds

Base - 24" W x 30" D x 24" H, 110 pounds

Power - 110 VAC, 60 Hz, 1400 watts

Operating Temperature - -30 to 120^{0}F

Environment - Waterproof, oilproof, dustproof, explosion proof, (internally pressurized with dry inert nitrogen, pressure switch power interlock)

Lamp Life - 6 months (12 hours per night)

Because light is mostly reflected at shallow illumination angles, fluorescence cannot be effectively stimulated within 6 degreees of the horizon. Thus, to achieve a range of 600 feet, the detector must be at least 60 feet above sea level to provide an illumination angle of more than 6 degrees. This maximum ration (10:1) of range to height represents one of the major installation considerations in some applications. The following specificiations would fall into a preliminary category.

Range - 600 ft. maximum, less in fog

Hours of Operation - 45 minutes after sunset to 45 minutes before sunrise

Elevation Scan - 6 to 30 degrees below horizon (adjustable) at 0.5 degrees per second

Azimuth Scan - $\pm$150 degrees (adjustable) at 2.5 degrees per second

Scan Pattern - Programmable

Alarm Criteria - Detection on two consecutive scans

Beam Size - 0.5 degrees elevation x 2.5 degrees azimuth (projects to maximum of 50 x 25 ft. on sea surface at 600 ft. and 6 degrees below the horizon)

Minimum Spill Size - 75% of beam area

Minimum Spill Thickness - 1 micron (at maximum range)

Display - Remote via RF or wire

Indicators - Power On
Equipment Active
Equipment Failure
Oil Alarm
Oil Type
Position

Cost:

The base price of a unit has been established at $75,000. Motorola AR.81 FM transmitter alarms are available at $2,500 which greatly reduce the expense of a travel line.

SPILL SENTRY

Manufacturer

Sentry Systems, Inc.
5304 Allum Road
Houston, TX 77045
(713) 721-0200

Operational Characteristics

Rather than being classified as an oil sensing system, this product would fall under the category of a spill prevention unit. It comprises a system of power actuators that operate loading valves and controls associated with tanker or barge loading operations. A master panel incorporates controls for opening, closing or throttling loading valves. It is also equipped with an "Emergency Shut Down Knob" (ESD Knob); the actuation of which shuts down the entire loading operation immediately. A lightweight hand carried "emergency station" equipped with one ESD knob on either the dock or the on-loading vessel can shut down the entire loading process once a potential spill has been sensed or is imminent.

Normally the manufacturer would send a company representative to survey and measure the dock, pipelines and valving to determine where the various mountings would be located and to determine the engineering requirements for either cylinder or rotary actuators for adaption of existing valves. This action can be eliminated if the plant can provide a detailed engineering description of the dock and its loading equipment.

Figure 11-4 indicates a typical installation of the system.

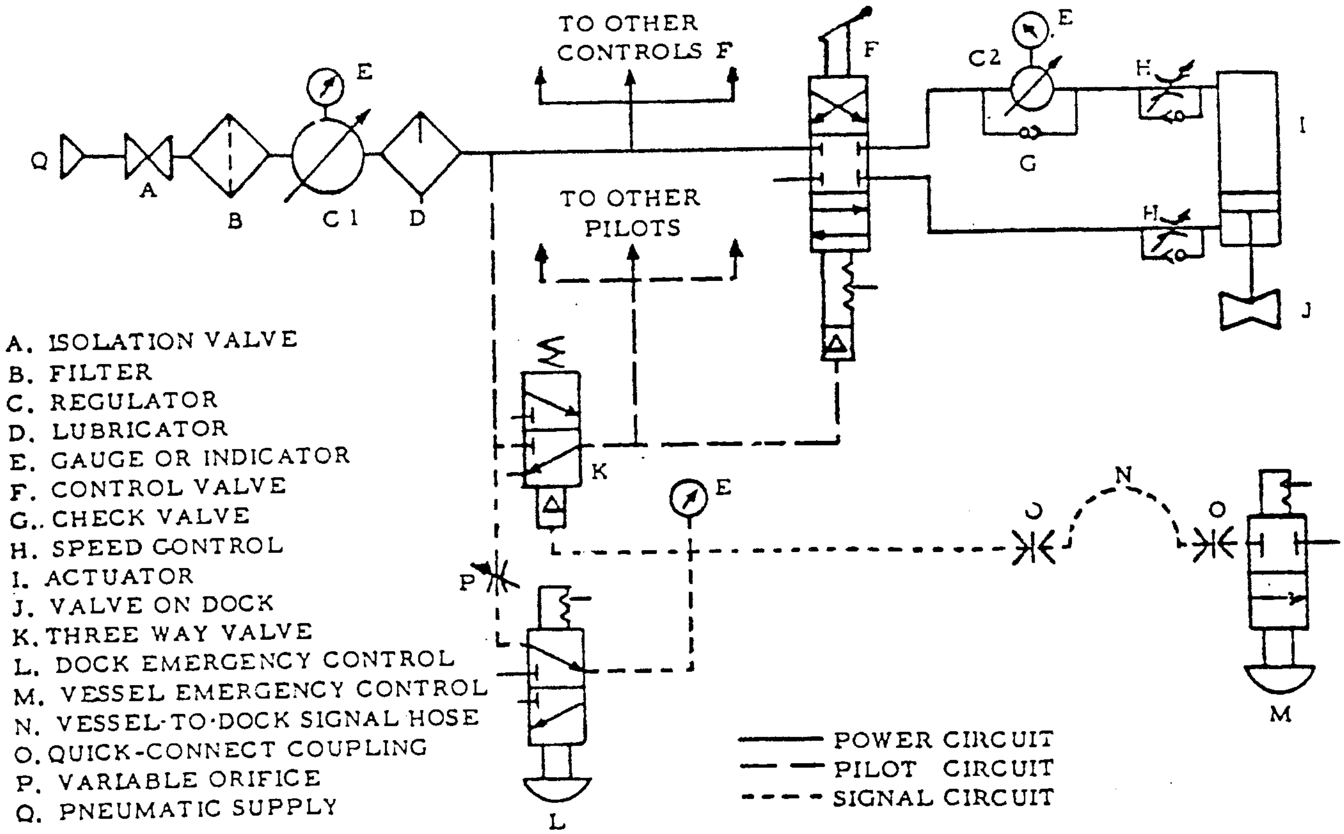


FIGURE 11-4. SPILL SENTRY SYSTEM

The Control Valves F. in the power circuit, are located on the Master Panel, and are positioned manually to open, close, or throttle the Loading Valves J. Speed Controls H govern the opening and closing rates. For gate valves, the closing thrust, supplied by Actuator I, is limited by Regulators C2, to assure that force for opening Valves J. will be greater.

During normal operation, pressure is maintained in the signal circuit, holding Valve K in the position shown. Actuation of Valves L or M, or breakage of the Hose N, as by excessive motion of the vessel, results in the loss of signal pressure.

This causes Valves K to shift, thereby initiating Emergency Shut Down.

When Valve K shifts, pilot pressure is applied at Valves F, shifting them to the extreme out position. This closes (or opens, if so intended) Vavles J, shutting down the loading operation. Valves J can be reset only from the Master Panel.

Not shown are other devices which can be incorporated in the system. Among these are sensors to detect level of liquid in the tanks, to automatically initiate EDS, sound an alarm, or perform other functions, such as shutting off pumps. Similarly, protective devices can be included to respond to excessive flow, pressure, explosive vapors, fire, or other undesirable or unsafe conditions.

Cost:

It is difficult to present a base price since the installation would differ by terminal; however, an average loading dock having 8 to 16 flow control valves would cost in the vicinity of $1,600.00 a valve to modify into an automated system.

References:

1. Manufacturers Sales Literature (as per each unit described).

2. Meeting J. L. Goodier with Baird-Atomic representatives.

3. Little, Arthur D., 1976. A Systems' Study of Oil Pollution Abatement and Control for Portland Inner and Outer Harbor, Casco Bay, Maine. Prepared for the State of Maine Dept. of Environmental Protection State House, Augusta, Maine, March, 1976.

12. WASTEWATER TREATMENT PONDS

12.1 General

At many production facilities the wastewater treatment ponds occupy more acreage than the production buildings. At one large installation, it is normal for the flow of process wastewater to run in the vicinity of 8 to 9 million gallons per day (gpd). Until a few years ago, up to 14 million gpd was treated. The reduction was obtained by tighter controls introduced by plant operators who concentrated on reducing the daily quantities of process water used. It is possible for most plants to locate phases in the production flow where the use of process water can be drastically reduced. Some plants are reverting to installations that recirculate cooling water systems. The water is recirculated to a cooling tower and returned in a cooled state to the process. The initial expense is eventually recouped from lower water and waste treatment costs and land reclamation.

An efficient waste treatment plant might include primary settling basins, aeration chambers, and secondary clarifiers. Special instrumentation can be provided at strategic locations to analyze the effluent flow. These instruments can monitor the process areas which discharge into the treatment ponds. Through their use it is possible to be promptly alerted to any change in flow that would give early warning of a spill.

12.2 Seepage Control

Until a few years ago few, if any, special precautions were taken to control seepage from wastewater treatment ponds or lagoons. As a result a number of Federal enforcement actions are in progress to correct ground water contamination from the seepage of oil, petrochemicals and hazardous materials. Monitoring wells have been drilled to determine the extent of vertical and lateral seepage. Damage has been so extensive that at some locations oil well water flood techniques have been investigated as a possible way of recovering floatable materials from contaminated aquifers.

An example of the acuteness of the problem was experienced in a nonoperational refinery that has a bad historic experience of inplant spills. However, the major problem came when the plant was in a bulk storage status rather than a refining process. The wastewater treatment ponds once idled lost their water barrier which normally kept the waste oil in suspension above the soil forming the bottom of the pond. The water was depleted by a combination of solar evaporation and earth percolation. Once the waste oil made physical contact with the earth, it seeped down into an aquifer. Residents of a residential community were subjected to an early indication when their well water began to have a gasoline odor. Later oily water was flushed into toilets. Eventually during a period of high water table, a mixture of waste oil burst through the bank of a creek almost a mile away from the waste treatment ponds. Recovery wells were used to recover the waste oil from the aquifer. In one year 200,000 gallons of oil were recovered for reprocessing. An early estimate indicated that as much as 1.5 million gallons of waste oil had accumulated in the aquifer. The cleanup action was expensive and of long duration.

From incidents as described, action taken to line holding and treatment ponds can eliminate both immediate and long range operational problems. When the cost of lining a holding pond is related to the expense of cleaning contaminants out of an aquifer, coupled with the adverse publicity that follows, such incidents, lining costs are negligible.

12.3 Sealants for Waste Treatment Ponds

There are a number of spray-on sealants that can be classified in groups as follows:

1. Alkyd Resins
2. Coal Tars and Asphaltic Products
3. Bentonites (not spray-on)
4. Exposies
5. Gunite
6. Polyvinyl Products
7. Rubbers
8. Silicones
9. Sulphur Compounds
10. Urethanes

Testing by the Canadian Environmental Protection Services has revealed that groups 2, 6, 8, and 9 have poor resistance when exposed to petroleum products. Group 2 was found to be unsuitable for application to soil. In brief the best suited potential products as revealed by testing were as follows.

The alternative spray-on product (Group 5) is Gunite, a mixture of sand, cement and water applied by pneumatic pressure through a "Cement Gun." The Portland Cement compound would be sprayed over reinforcing steel at a cost of $\$2/ft.^2$ Canadian testing did reveal problems with cement covering on heaving ground, such as that exposed to Arctic deep icing conditions. Gunite is, however, used extensively in moderate climates.

Volclay-American Colloid Company, Skokie, Illinois - a sodium bentonite based product that can be applied at $65¢/ft.^2$

Sucoat-Chevron Chemical Company - a thermoplastic molten sulphur and organic plasticizer and inorganic filter which costs $\$1.75/ft.^2$

The application of the spray-on material should cover the entire storage area and the sides of the retaining dikes.

There exists a wide range of flexible membranes that can be used to line settling, solar evaporation and waste-water retention ponds. It is possible to safely store effluent containing aggresive organic materials, such as certain crude oils in liners of Neoprene fabrication.

Hydrocarbon rubber sheeting also offers good resistance to acids and bases. This material is also capable of containing effluents having a high temperature, especially when they are aggrevated by chemical attack.

Synthetic rubber liners have become widely used and have a long history of successful operation.

Installation can be conducted by plant personnel. It is considered advisable, however, to have the installation conducted by an experienced contractor/supplier.

The Watersaver Company, Inc., Denver, Colorado, a liner supplier, offers the following advice on membrane installation.

<u>WATERSAVER COMPANY, INC.</u>

Pond and Reservoir Membrane Liners
General Instructions for Jobsite Preparation

1. The earth upon which the liner will be placed must be smooth and free from sharp rocks, roots, vegetation, and other foreign material. A compacted substrate is advisable to prevent settling. Compaction around pipes and structures is especially important.

2. Check measurements and grades prior to start of liner installation. Surveyor control stakes should be left in place to assist in placing the lining panels.

3. Dig the anchor trench as shown on the shop drawing or the engineering drawings. A typical cross section is found on TDK-74, where a minimum 12" setback is shown. ALWAYS THROW EARTH FROM TRENCH AWAY FROM SIDE SLOPE.

4. Crew size will depend on the project size. A minimum of 6 men is required, most projects need at least 10 men to spread panels.

5. Old tires or sand bags will be needed to keep the material in position during windy conditions. Normally 10 tires per panel up to 50 tires are required.

6. Tools and equipment not supplied by Watersaver include: wiping rags, paint brushes for adhesive, rakes and shovels. Liner panels may weigh as much as 4000#. A large front end loader or forklift will be required to assist in the spreading of the lining material. Palleted cartons are about 84" x 36" x 36".

7. Cements and adhesives shall be kept from extreme heat and cold.

8. A Technical Services Representative is available from the Watersaver Co. for a small fee when made part of the purchase agreement.

9. All PVC (Vinyl) liners must be covered with earth if an extended life is expected. A minimum of 12" of earth should be placed on the bottom and slopes. Side slopes of 3:1 or less are normally required to hold the earth cover. Windy conditions may require special rip rap considerations.

10. Driving on the liner is permitted only when the liner is first covered with 12" of earth. If an area is to have sustained traffic 24" of cover is advised. Damage to the liner must be repaired as it is discovered!

11. Structures including pipes, splash pads, inlets, outlets, and headwalls hould be finished prior to placement of the liner. Prefabricated corners and pipe seals are available for flashing the liner to structure.

    This above is furnished to aid in planning liner installations. Watersaver Co., Inc. as a supplier of materials only, does not assume responsibility for errors in design, engineering, quantities, or dimensions.

Figure 12-1 illustrates the techniques for membrane liner installation.

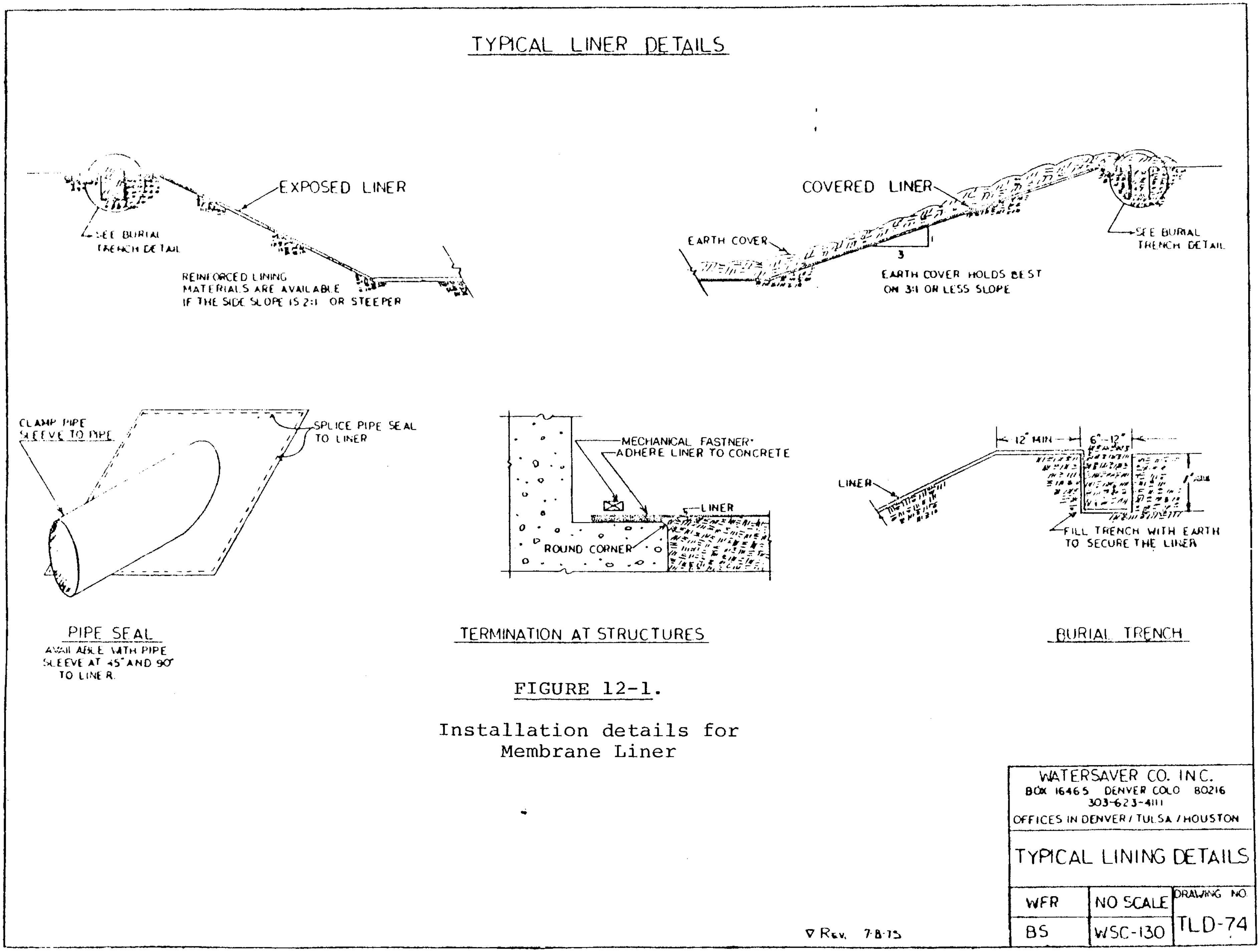


FIGURE 12-1.

Installation details for Membrane Liner

12.3.1 Liner Costs

The cost per manufacturer may vary slightly. The following prices are quoted only as a typical costing range.

Vinyl (PVC) Liners vary in cost from around $.135/ft^2$ to $.295/ft^2$, the price being dependent on the thickness of the membrane and the quantity ordered.

Oil-Resistant Vinyl (OR-PVC) Liners range from $.35/ft^2$ to $.375/ft^2$ based on stipulations as above.

Chlorinated Polyethylene (CPE) Liners - $.35/ft^2$ to $.435/ft^2$.

Chlorinated Polyethylene (CPER) Reinforced Liners - $.61/ft^2$ to $.58/ft^2$. (Price reduction by quantity used.)

Dupont Hypalon (HYP) Reinforced Material - $.60/ft^2$ to $.57/ft^2$.

Neoprene (NED) 16 oz/Square Yard Reinforced 22 x 22 - 840 Nylon - $.56/ft^2$.

The solvent splicing and bonding adhesive averages about $16/gallon.

Firestone Coated Fabrics Co., Magnolia, Arizona, has developed a "Farbritank" capable of containing up to 1,000,000 gallons of liquid. This tank could have application for the storage of oil contaminated water until the oil could be recovered for reuse. The covered tank may have desirable features for use in hurricane and flood territory where the contents of treatment ponds have been "lifted" and spread over a wide land area.

The manufacturer provides the following description of his product.

This container is a lightweight rubber or plastic-coated fabric tank that is supported and protected by earthen dikes. It is used to store water for fire protection, drinking and process water for domestic and commercial uses and as a bulk storage facility for liquid chemicals and fuels.

In a fully unfolded and unfilled condition, a Fabritank container resembles a pillowcase seamed on four sides. When it is placed in an excavation with sloped sides filled, it becomes, in effect, an integral liner with floating roof.

A filler and drain fitting is located on the bottom of the tank. As the tank is filled, the top or roof portion floats upward. It will easily and safety support the weight of a man when filled to maximum capacity.

Since the tank is never filled beyond its rated capacity, expansion and contraction of both the stored liquid and embankments are accommodated easily by the coated fabric. This eliminates the need for open venting and excludes the possibility of contamination or evaporation of the stored product.

The earthen embankments are the backbone of the Fabritank containers. They support it and hold it securely in place. To guard against erosion during rain and melted snow runoff, drains are incorporated in the design. Also, slopes are planted with grass or heavy rooted plants. This feature enhances the appearance of the installation and creates new opportunities to architecturally blend the installation with modern plant and recreational facilities.

To insure maximum service reliability, the tank is vulcanized and fully assembled at the factory. After testing it is folded, rolled on a mandrel and wrapped with a protective cover for shipment. Installation is usually accomplished in one day with a supervising Firestone-designated technician and a small crew of men.

Fabritank containers are available in 12 standard sizes from 25,000 to 1,000,000 gallons. Other sizes are also made to order.

Such a tank could be used as an oil/water separator using a settling process. An imbiber valve drain (See Sections 4.8.1.2 and 4.10.2) would permit water drainage and oil retention for reclamation purposes. Figure 12-2 denotes tank sizes and method of installation.

Note: Although Watersaver Company and Firestone, Inc. information was used in this report section, it should not be construed as endorsement of a particular product.

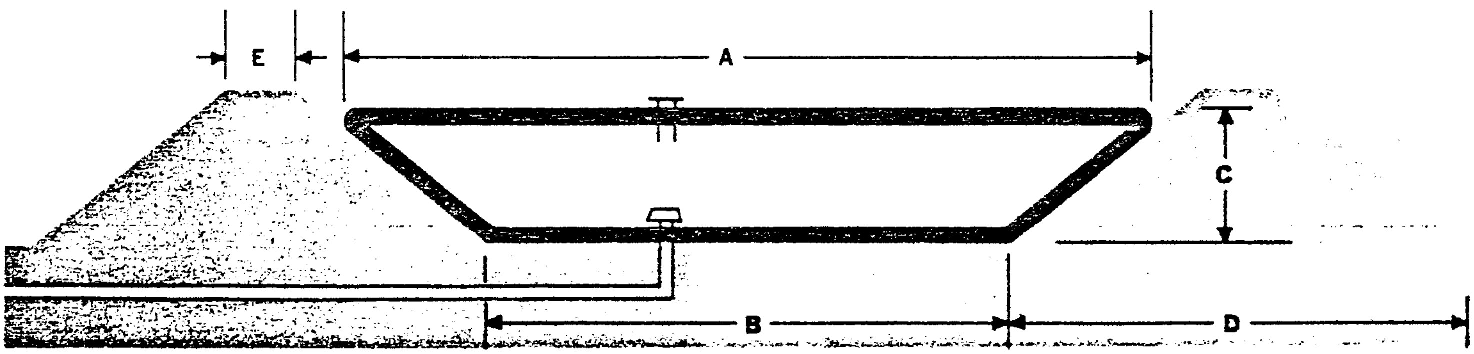
12.3.2 Monitoring Leachate From Holding Ponds

It has become a standard practice to drill leachate monitoring wells around holding ponds. The procedure practically duplicates monitoring systems for solid waste disposal sites. A typical procedure is to drill sampling wells just below the water table. A screen is provided to restrain the entry of solids into the sampling tube. The screen intersects the water table as depicted in Figure 12-4. Although

EMBANKMENT FABRITANK SIZES* AND DATA

NOMINAL CAPACITY (GALS.)	TANK DIMENS. (FT.)			DIKE DIMENS.		AVERAGE EARTH DIKE (CU. YDS.)	TANK NET WEIGHT (LBS.) (APPROXIMATE)
	A	B	C	D	E		
25,000	33.2	15.2	6	22.5	1.5	549	836
50,000	41.5	17.5	8	29.0	2.0	1045	1,286
100,000	52.4	22.4	10	35.5	2.5	1855	2,045
200,000	66.4	30.4	12	42.0	3.0	3137	3,269
300,000	77.7	41.7	12	42.0	3.0	3628	4,414
400,000	87.2	51.2	12	42.0	3.0	4041	5,506
500,000	95.6	59.6	12	42.0	3.0	4402	6,563
600,000	103.1	67.1	12	42.0	3.0	4728	7,597
700,000	110.0	74.0	12	42.0	3.0	5028	8,615
800,000	116.5	80.5	12	42.0	3.0	5307	9,617
900,000	122.5	86.5	12	42.0	3.0	5568	10,609
1,000,000	128.2	92.2	12	42.0	3.0	5816	11,593

Note: A — Tank Top—Square B — Tank Bottom—Square C — Tank Depth D — Earth Dike—Base E — Earth Dike—Top



EMBANKMENT AND TANK CROSS SECTION

All tanks are oversize 10%.
***Other sizes available on request.**

NOTE:
Tank dimensions A, B & C are shown to illustrate standard available sizes and capacities. Embankment dimensions D & E and average earth dike quantities are to be considered as schematic illustrations only. Since structural characteristics of soil vary, it is important that the embankment design be determined by a qualified civil or consulting engineer.

FIGURE 12-2.

this type of well is routinely used, a single well is not effective in providing information on the vertical distribution of the contaminant. The drilling of at least four wells is advisable--one upgradient to determine subterranean baseline conditions, two spaced down gradient with an additional down gradient well some distance away from the other two wells. If only hydrocarbon products are involved, the well need only enter the upper surface of the ground water. These wells cost between $8 to $10/ft to drill.

The US/EPA recommends the following well drilling procedure:

- drill a 152- to 203-mm (6 to 8 inch) diameter borehole with a hydraulic rotary rig to the bottom of the aquifer*;
- set 102-mm (4 inch) diameter slotted PVC well screen and PVC casing;
- backfill with a gravel pack or formation stabilizer;
- place a concrete collar around the well casing at ground surface to prevent downward leakage of rainwater or other fluids.

Once completed representative samples can be either baled or pumped from the well for analytical purposes.

---

*An investigation for oil seepage would not require this depth - refer to Figure 12-4.

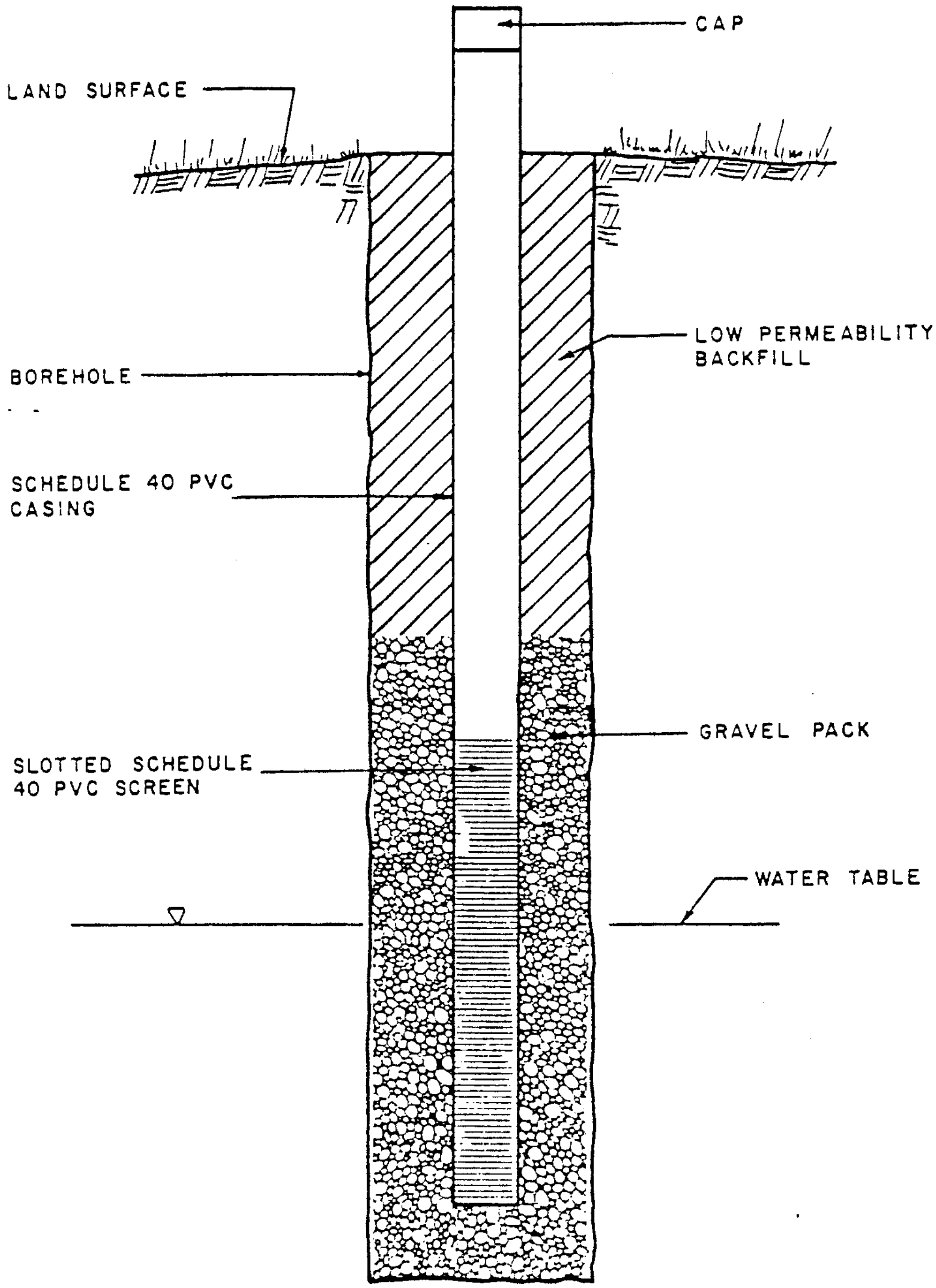


FIGURE 12-3.

Typical Monitoring Well Screened Over a Single Vertical Interval
(Illustration US/EPA)

There is, however, a direct readout system available that should give immediate warning to a central system if hydrocarbons seep from a holding pond. The unit, a product of Pollulert Systems, Mallory Componenets Group, Indianapolis, Indiana, is known as the "Pollulert Hydrocarbon Detector." It has the capability of detecting oil in surface water, dry sumps, and on water, including ground water. The system constantly monitors a group of detection probes at locations selected for specific applications. It flashes a warning signal whenever hydrocarbons contact the probe. At the same time, it can be equipped to activate the alarm devices, to automatically telephone supervisory personnel or to activate pumping equipment which will collect and recover the spilled material. Early detection makes it possible for leaks and spills to be detected before large volumes of material are discharged and wasted.

The system is in line with desired automation practices. It is self-cleaning. It has solid state microprocessor-based circuits and has self diagnosis circuitry. The pressure of hydrocarbons is detected by evaluating the thermal conductivity of the material the probe contacts. Patents are pending on this recently developed spill detection system. Figure 12-5 depicts the ground sensing unit and the readout unit.

For ground water monitoring, a four sensor unit costs \$1295. The cost for cable ranges from .35/ft. to \$1.45/ft. To this would be added the well drilling at \$8 to \$10/ft.

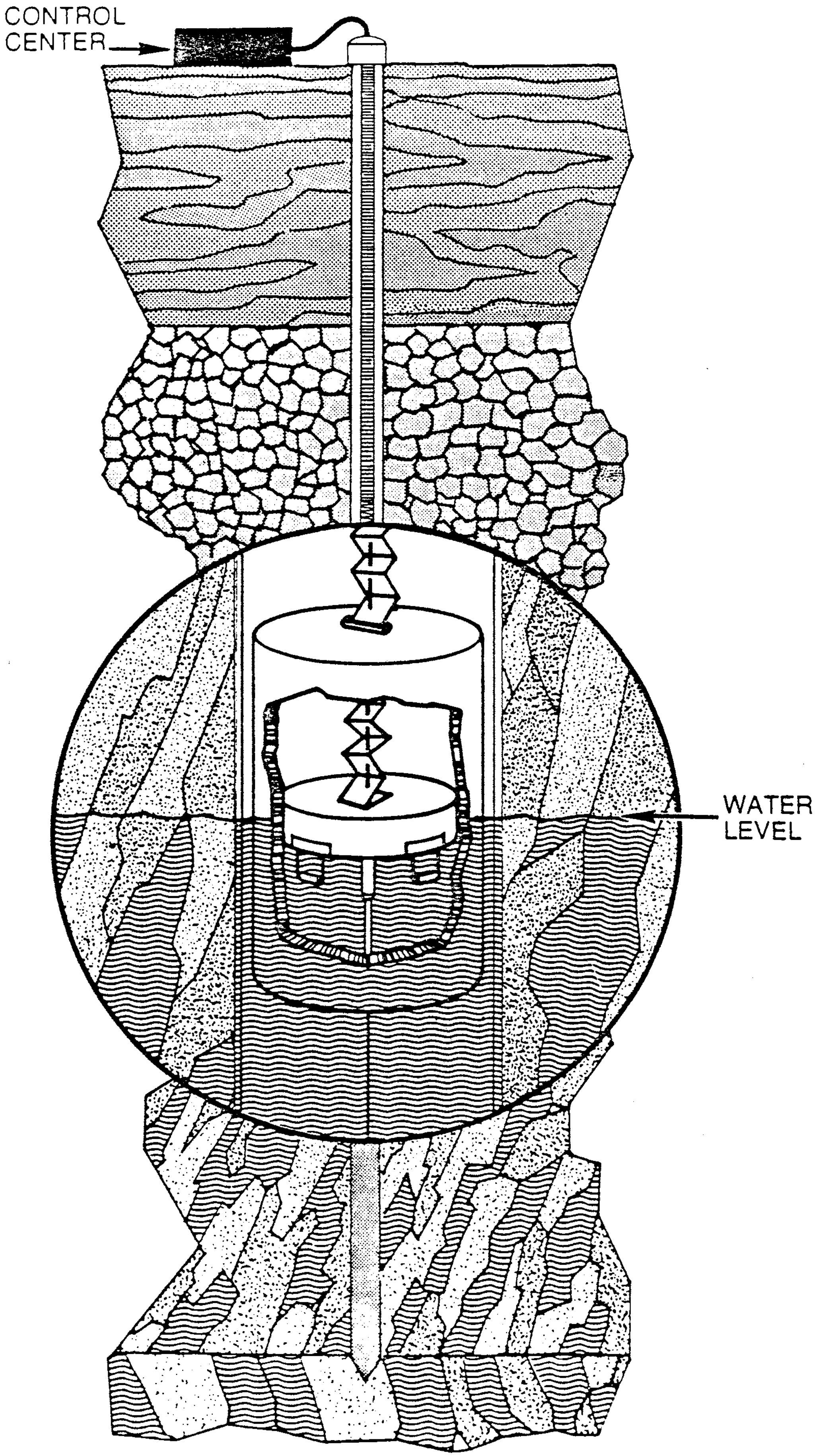


FIGURE 12-4. Pollulert Ground Water Monitor
(Photograph Courtesy Pollulert)

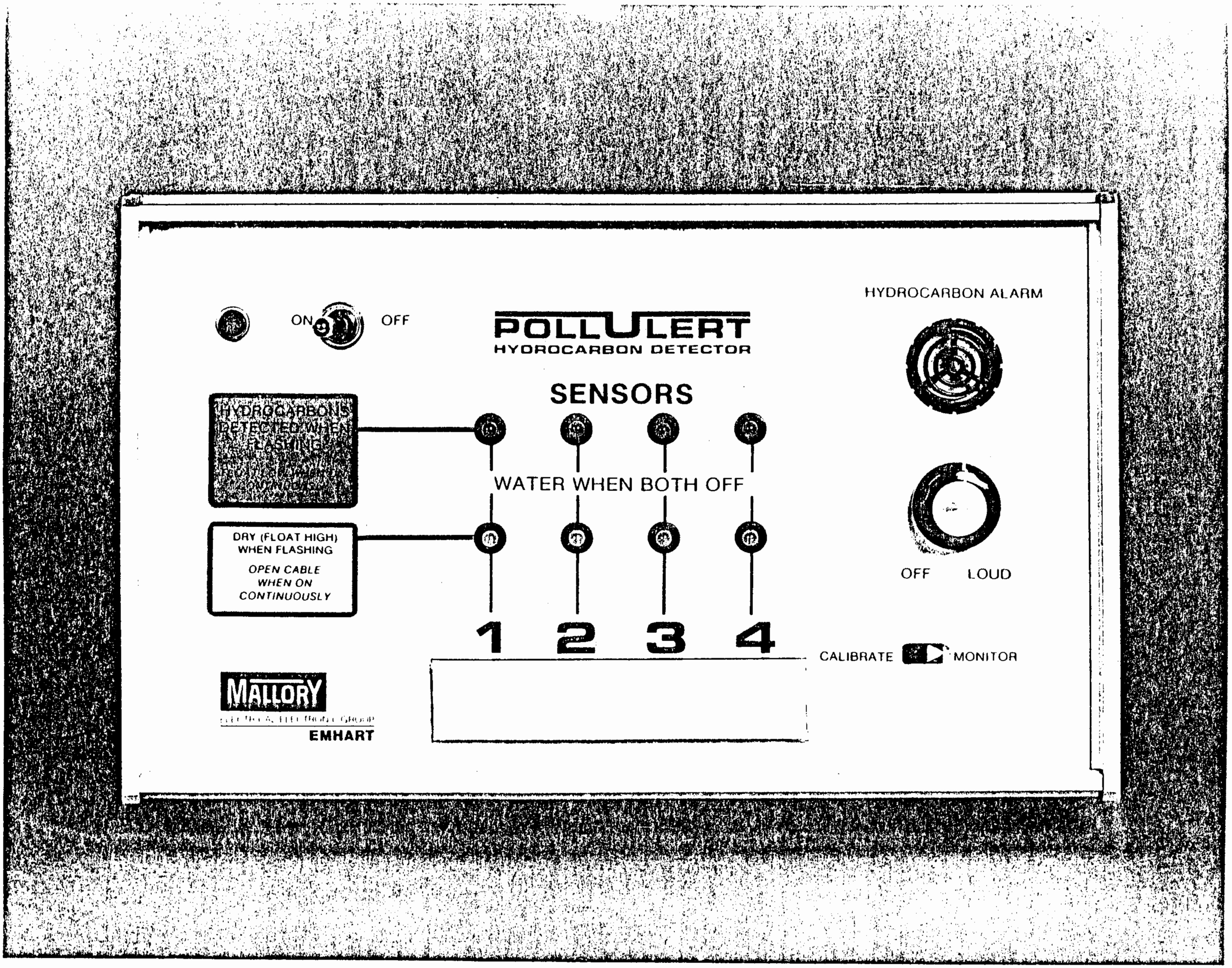


FIGURE 12-5. Pollulert Hydrocarbon Detector
(Photograph Courtesy Pollulert)

References:

1. Review of Spray-on or Grouting Sealants for Petroleum Product Storage Areas and Dykes in the North. Economic and Technical Review Report, EPA 3-EC-76-12. Canadian Impact Control Directorate, October 1976.

2. Watersaver Company, Inc. Sales Brochures and Letter/ W. J. Slifer, President. 3/17/77

3. Procedures Manual for Ground Water Monitoring at Solid Waste Disposal Facilities. US/EPA 530/SW-611. August, 1977.

4. Pollulert Systems Sales Brochure, Form No. P-100

5. Firestone Coated Fabrics Company Sales Bulletin M-010 (1978).

13. PERSONAL QUALIFICATIONS AND TRAINING

13.1 General

The indoctrination and training of a new employee has considerable bearing on the workers usefulness for his entire tenure with an organization. Training by direct work foremen is not always a satisfactory process. The foreman with many years of experience may not have the ability to transfer his knowledge in a desired manner. Frequently he will try to impart 25 years of experience to a new worker in 25 minutes or less. It is almost impossible for any newly hired individual to mentally retain a long series of work instructions. Frequently the foreman assumes that the new employee has mentally digested instruction when he has not. The new worker, too embarrassed to admit the situation (the foreman might think he is simple) enters a work assignment with only partial or a complete lack of knowledge. In an industrial or federal complex handling and storing flammable products, such a situation cannot be tolerated.

The industrial insurance research of H. W. Heinrich (deceased Superintendent of the Travelers Insurance Company Engineering and Loss Control Division) revealed from a study of accident causes that 88 percent resulted from human failure, 10 percent from mechanical failure, and 2 percent unpreventable acts of God, etc. In situations where the single action of an individual can bring about catastrophe, more intensive training techniques are warranted. This section defines, as far as practical, methods and sources of training for plant workers.

13.2 Tankermen and Dockmen

Tankermen must pass a USCG examination before they can ply their trade. Presently the status of tankermen is being redefined in a new Federal regulation that has not yet been released for public review. It appears that tankermen will be subjected to grading and that attendance at an industrially operated training school will be a mandatory step toward qualification.

The USCG published three instructional manuals devoted to tankerman training--two will eventually be updated to meet the content of the proposed regulation. The third publication is out-of-date and is no longer printed. The content should, however, be a good guide to safe practices. The publications are:

- CG-174 "A Manual For the Safe Handling of Flammable and Combustible Liquids" (To be updated)
- CG-327 "Fire Fighting Manual For Tankermen" (To be updated)
- "Oil Pollution Control For Tankermen" (No longer used or available)

Contact with Mr. Brant Houston,* President, Houston Marine Consultants Inc., 5616 Jefferson Highway, New Orleans, Louisiana 70123 (504/733-9013) revealed that the Maritime

---

*A retired USCG officer

Training Services Division of his organization provides tankermen training. The concern provides a two-day training course every two months at a cost of $150. The course, geared toward attendees passing the USCG tankerman's examination, covers the following topics:

- Cargo handling
- Pollution prevention
- General safety
- Firefighting
- First aid

The training involves classroom instruction using lectures, slides, and overhead transparency projection as training aids.

Other known training sources include the following:

- National River Academy,
  Helena, Arkansas
- Western River Training Center,
  Greenville, Mississippi
- Harry Lundeburg School of Seamanship
  Piney Point, Maryland (This is CIO
  Seaman's International Union School)
- National Maritime Union,
  New York, New York
- Marine Engineers Benevolent Association,
  Baltimore, Maryland
- Masters, Mates, and Pilots Union (MITGS),
  Linthicum Heights, Maryland

The various state sponsored maritime academies also provide oil product transfer training but it is not known if these courses are open to the employees of industrial organizations. This is a factor worthy of local investigation to curtail travel expenses.

Ideally, dockmen and tank field employees could benefit from available tankermen courses.

Company-sponsored inhouse courses can be most valuable. In this respect, the USCG Maritime Safety School, Yorktown, Virginia (Cdr. Fred Halberson) has developed a unique training aid for both tankermen and dockmen. For training of USCG personnel the school has developed a wheeled plexiglass model of a multi-compartment transportation barge, complete with engine and pump and pipelines. A compatible loading/unloading dock is available equipped with Chiksan torsion loading arms and flexible hose lines (actually modified water hoses). It is possible to load and offload water to and from the barge for training purposes. There presently appears adequate sources of educational facilities for these categories of workers. Additional needs may develop once Federal law requires classroom training for workers prior to licensing same.

Many marine transportation organizations hire a tankerman on a contractual basis to offload their barges and tankers. Frequently this contractual source can be a lone individual who has established himself in his occupation and has developed a series of clients who use his services on an "on-call" basis. It is difficult to introduce these individuals into a company operated training program due to their independent status. Under such circumstances it is imperative that the contractual tankerman's experience and track record with respect for product spills be closely investigated. The USCG states that men in this category will be automatically licensed to continue operations under a "grandfather" clause agreement.

13.3 Pump Room Operators

In many facilities the duties of these workers also includes the additional duty of boiler operators involved in process steam generation---the pump room being immediately adjacent to the boilerroom. The workers generally hold state operating engineer's licenses if a high pressure boiler (maximum working pressure over 15 psi) is involved. The holding of a license does not necessarily indicate that the holder is fully competent with every type of pump or pumping operation. There are many engineering differences with every pumping system. All new employees should be subjected to a short probationary or apprenticeship period until they have proven complete competence and knowledge in the entire pumping system. Many states have regulations pertaining to the period of time that a boiler attendant can be absent from the boilerroom. The hazards of unattendance in either the boiler or pump room approach equal proportion. An adequate staff should be available to avoid prolonged absence from any of the work assignments.

13.4 Maintenance Workers

Workers in this group have a vital part to play in any spill prevention program. These workers while in a mobile status travel the length and breadth of the plant many times during the course of a work day. They enter areas not normally seen by other plant workers. In this respect they can become the eyes and ears of the plant in leak detection and the advance notification of potential leak sources.

The maintenance staff should have an intimate knowledge of weak links in the spill prevention chain. On an alternate basis (to gain different viewpoints) a maintenance worker, complete with a specially prepared checklist, should inspect the plant property on at least a weekly basis. The checklist should be presented to the direct work supervisor at the termination of the plant survey. The supervisor should sign and date the checklist, later indicating the date and action taken to correct a leak or potential spill source.

During plant safety meetings, the findings of each survey should be a topic of discussion by the "surveyor" of the week."

13.5 Tank Field Gagers

These workers should if practical be included in the maintenance worker cycle and be an integral part of at least the section of the safety meeting devoted to the findings of the weekly plant survey. Workers in this category should also be encouraged to report any mechanical or operating deficiencies that could contribute to a spill.

13.6 Tanker, Tug, and Barge Crews

Unless company employees are involved, these workers develop educational difficulties. Visiting crews should, however, be fully briefed on the plant's operational procedures. They should be introduced to plant personnel who will work on the loading/offloading operation. The specific duties of each individual should be explained and a direct line of communication should be established between the operating personnel. The communication system can be word of mouth, loud hailer, or two way radio depending on the distance involved.

As discussed previously in this manual (Section 10, Loading/Unloading Piers) a company representative or supernumerary should be assigned to monitor the entire product transfer operation using a prepared checksheet. Through this medium the plant's loading/offloading requirements will gradually become known to both company and visiting crew members.

13.7 Vehicular Transportation Workers

13.7.1 Company Employed

The selection of tank truck operators is an important part of the educational process. The past accident record of a prospective employee should be fully investigated through previous employers and state motor vehicle departments in past states of residency. Investigations should also be made into the excessive use of alcohol or the use of drugs.

It is preferable that an organization employ a driver instructor on a local or regional basis. This individual should interview and test the driver before and immediately after employment. Once hired, the driver instructor should ride with the new employee for possibly a week to insure that the selected individual has the desired driving capabilities and driving habits.

Driving routes should be selected by management to circumvent road hazards, heavily traveled areas, railroad crossings, dangerous bridges, and the like. The driver should be instructed not to deviate from the selected route unless emergency situations develop.

The driver should make a daily check of his vehicle preferably using a checklist technique. Any mechanical deficiencies should be corrected before the vehicle is permitted to leave the terminal.

Slightly more than 29 percent of reported truck accidents in which mechanical defects or deficiencies contribute to the cause are caused by tire failure; 19 percent are caused by defective brakes. Coupling (fifth wheel) defects cause 13 percent of the accidents and wheel defects and faulty lights each contribute about 10 percent of total accidents. Daily inspection and prompt maintenance procedures can prevent many of these accidents. Such procedures lessen the risk of cargo spills and also improve safety in general.

The operator should also be instructed on procedures that can be introduced to minimize or contain a spill during highway travel. It is important that the driver has the name of a person or organization that he can call for assistance in any emergency in each town enroute. This source of assistance should be called in addition to the local authorities such as fire and police. The driver should also have basic tools to contain spilled material. This should consist of a spade that can be used to dam drainage ditches or other locations needing earthen containment. A box of heavy duty large size garbage bags should be provided that can cover storm drains. The bags can be spread over the drain and held in place with shoveled earth. This action prevents spilled hydrocarbons from entering a storm sewer which ultimately drains into a public watercourse.

Another important educational process can be introduced into driver safety meetings. Normally, the drivers sit back and wait to be "entertained" by a safety movie and a talk by some safety authority. This has become a standard procedure for safety meetings. It is suggested that through the medium of an overhead transparency projector, that each driver involved in an accident be called upon to describe the details of the incident. The remaining drivers can then be encouraged to provide peer review. In this manner many years of truck driving experience can be put to educational use. The final result provides greater benefits than safety talks--many of which are made by individuals with little or no truck driving experience.

A common carrier driver's education process is needed to gain spill-free truck loading. Once on the highway the cargo is in the care and custody of the carrier, beyond the responsibility of the shipper. Carriers who have a good accident/spill-free record should be selected and a review of their educational and safety program is a normal procedure.

Each driver should, however, be given detailed instruction on the plant's loading procedures. Plant supervision should be closely maintained on all new drivers. This should not be relaxed until a number of loadings have been successfully completed by the visiting driver. It is also possible for plant management to monitor loading operations through strategically positioned closed circuit television cameras (CCTV). These systems are described in detail in Section 14, Plant Security.

The educational demands are dictated by the size of the plant, the number of employees and their specific duties.

Since plants differ extensively, this section should be considered as providing only the highlights of the educational process, parts of which may be new to some organizations.

14. PLANT SECURITY

14.1 General

Nationwide surveys of plant properties indicate a dire need for improved security measures at most facilities. There has been no federal regulations, voluntary codes, or industrial guidance developed in this respect from any central source. The vulnerability to sabotage, vandalism, and malicious-mischief is alarming. During a period of civil disobedience or military attack vast quantities of highly flammable, explosive products could be released and ignited to develop a holocaust. Most waterfront facilties are fenced on only three sides; the shoreline side of the plant and the loading/unloading piers are open to unauthorized access. Master flow control valves and drainage valves from diked areas are more often than not unlocked, presenting an easy target to the saboteur. In a similar manner, bulk tank water draw valves, normally designed to be padlocked either lack the necessary padlock or the padlock is left on the ground near the valve.

Two sizeable spills have been investigated by the authors whereby a person unknown opened the valves of an asphalt plant to release between 5000 to 8000 gallons of heated (180°F) bitumastic product. The hot fluidized material drained into a marsh causing considerable damage to the vegetation and wildlife. The action was so "successful" that five months later a similar act of sabotage was performed at another company owned location. In this incident 60,000 to 74,000 gallons of hot asphalt was released into a wildlife habitat. Both plants were unfenced, unlighted, unattended, and the natural drainage permitted the released liquid to flow to the nearest watercourse.

In Texas City, TX a disgruntled employee of a chemical and waste oil disposal facility opened the unlocked valves of a waste oil storage tank causing a 6000 bbl spill, 200 bbl. of which escaped into a shallow water bayou.

Other instances of vandalistic spills reported in the 26 October 1979 issue of the Oil Spill Intelligence Report (OSIR) are as follows:

"Up to 42,000 gallons of kerosene spilled from a 10-inch Buckeye Pipeline Company pipeline in Staten Island, New York on 18 September after vandals reportedly dug trenches to gain access to the pipeline and attemped to tap the line by boring into it. OSIR sources said that the vandals used the proper equipment for tapping the line and probably knew the pressure within it. The U.S. Environmental Protection Agency (EPA) told OSIR that the vandals left some of their equipment behind when they fled from the site and that they may have attempted to tap the pipe on the assumption that it contained gasoline."

"Up to 25,000 gallons of kerosene have been recovered, according to Coastal Services Co. Inc. of Perth Amboy, New Jersey, the cleanup contractor for Buckeye.* Coastal Services dug trenches and used sump pumps, 3M sorbent pads and boom,

*Buckeye Pipeline Company

a Seaward International Inc. Slurp skimmer, and 5 vacuum trucks to recover oil from the State Island marshland where the bulk of the oil spilled. Coastal said that the remainder of the oil either evaporated or seeped into the ground. OSIR learned that the cleanup cost Buckeye an estimated $50,000."

"In another recent vandalism incident, nearly 11,000 gallons of kerosene spilled from a Gilbert Distributing Co. tank in Havre de Grace, Maryland on 23 September when vandals reportedly dismantled a filter device on a pipeline carrying oil from a Gilbert storage tank to a distribution terminal. The kerosene overflowed the dikes surrounding the tanks, and according to the USCG, about 6,000 gallons reached the Susquehanna River, 50 meters away. The kerosene saturated the ground between the Gilbert facility and the river and damaged at least 1 private boat dock. The Gilbert cleanup contractor, J & L Industries Inc. of Baltimore, MD recovered most of the product using portable pumps, a 5100-gallon vacuum truck, and disposable absorbents."

"In addition to these incidents, OSIR has reported the following major spills resulting from vandalism in the past 2 months: 1) vandals reportedly opened valves at a Stockyards Service Co. facility in Sioux City, Iowa, on 22 September, causing 74,000 gallons of oil to spill. (OSIR, 19 Oct. 1979, p. 2); 2) unidentified persons reportedly opened valves on 4 Pocahantas Coal Corp. tanks near Garrett, PA on 26 October, allowing 32,000 gallons of diesel fuel to spill. (OSIR, 5 Oct. 1979, p. 2.); and 3) an estimated 30,000 gallons of oil spilled when vandals reportedly opened valves at a Conrail fuel storage tank near Pittsburgh, PA on 12 September. (OSIR, 21 Sept. 1979, p. 3)." *

There are obviously many more spills that can be attributed to vandalism. However, the few incidents listed should clearly indicate the extent of the problem.

As an aid to introducing tighter security measures in bulk liquid storage plants, this section is devoted to procedures that once implemented should aid in reducing "intentional" spills.

14.2 Fencing

Fencing does not provide maximum security, it only restricts or makes it more difficult for unauthorized persons to gain plant entry. The fence should be considered as providing only meager or minimum protection. Under most circumstances it would preclude the entry of children or persons intent on malicious mischief. The storage of highly flammable, explosive materials warrants added protection, over and above a standard metal fence.

14.2.1 Gauge of Fence

There currently exists on today's market a wide variety of fences, fence posts, gates and surmounted barbed wire/tape of different makes and manufacturers. Security fences are most commonly constructed within a three gauge size of either 11 gauge (residential fencing), 9 gauge (industrial fencing) or 6 gauge (prison security fencing). Most installations, however, consist of 2 inch galvanized steel diamond mesh configuration.

---

*Cahners' Publishing Company, 221 Columbus Avenue, Boston, MA 02116

14.2.2 Coatings

Organic coatings provide decorative functions in fencing applications. In addition organic coatings are the means for providing color to the fencing and add attractive value to the installation. A variety of organic coatings are suitable for fencing applications such as polyesters, vinyls, acrylics, etc. Suitable formulations should be selected for optimum adherence, weatherability, and color stability. Colored fence is used mostly for residential purposes and has only a thin coating of galvanize under the vinyl thus extending the life of the fence.

Zinc coatings on steel provides corrosion resistance by protecting the steel base through electrochemical sacrificial action. As long as there is zinc present the steel will remain unaffected by the corrosive action of the environment to which the coated steel is exposed. The galvanized coated fence is available as 1.2 or 2 ounces finish coating per square foot of wire.

The most utilized aluminized fence consists of one coating .40 oz. per square foot of wire and makes a most secure fence. Areas where facilities are subjected to salt air and/or extreme bad weather conditions warrant this type construction. The fabric should be woven from 9 gauge (coated size) wire in a 2 in. mesh. The tensile strength of fabric should be a minimum of 80,000 p.s.i. Fabric 72 in. high and over should be knuckled at one selvage and twisted at the other selvage (Figure 14-1). The minimum fence height should be at least 8 feet high above ground (optimum security fence height is 10 feet) surmounted by some type barbed wire/tape.

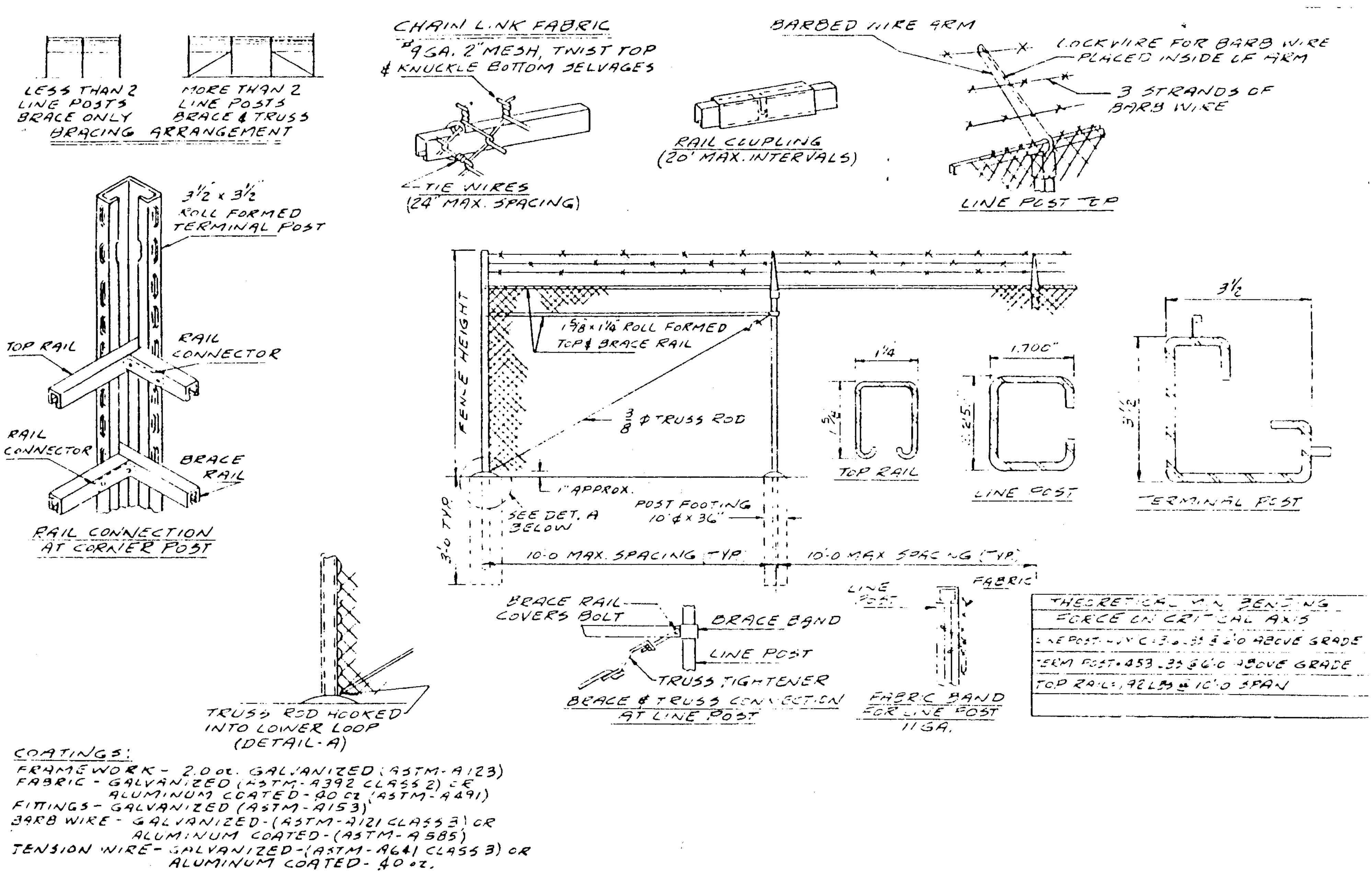


FIGURE 14.1 Fence Details with Top Rail and Heavy "C" Line Post. Illustration -- Courtesy, United States Steel Corporation, Cyclone Fence

14.2.3 Post Configurations

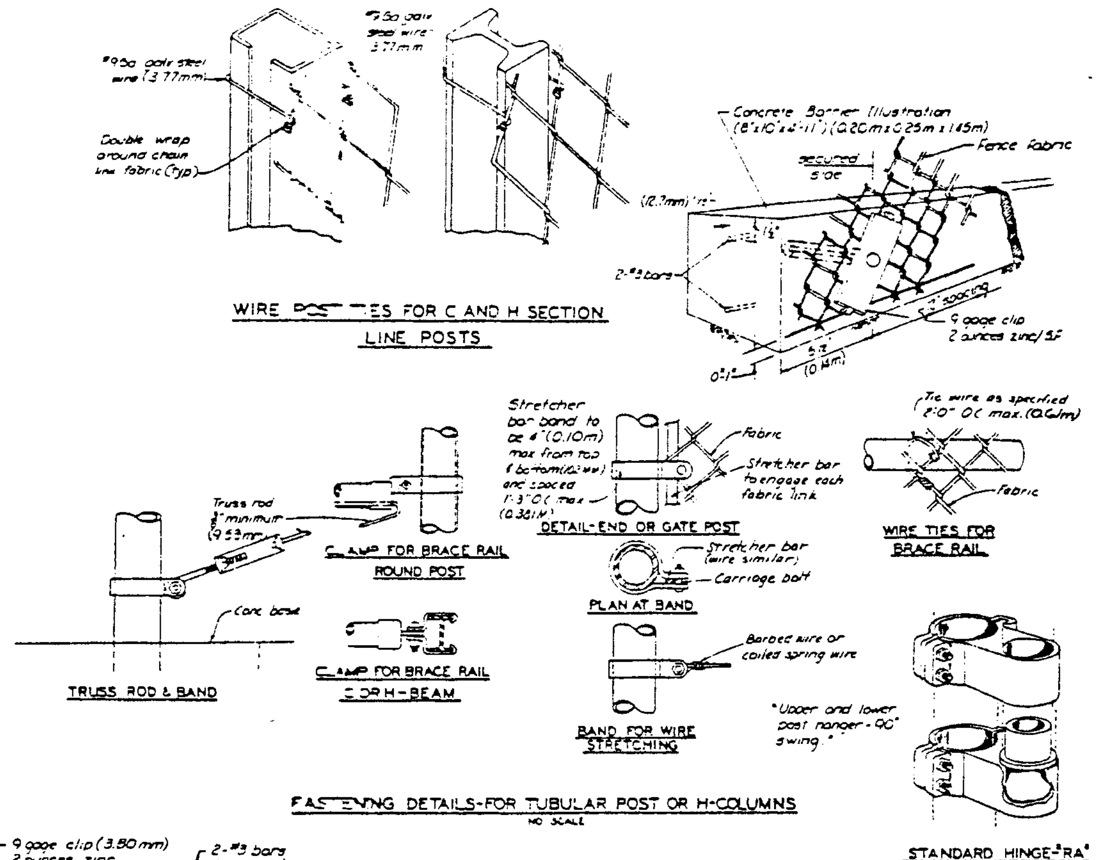
Many years of research have yielded designs which utilize a more efficient shape of steel to achieve a greater bending strength than the tubular shaped equivalent. This design is called the C-section post. This section is coated with two ounces of zinc per square foot. It is well suited for drive post construction, and is not subjected to the water entrapment potential of conventional tubular posts should fence caps be lost qf misplaced.

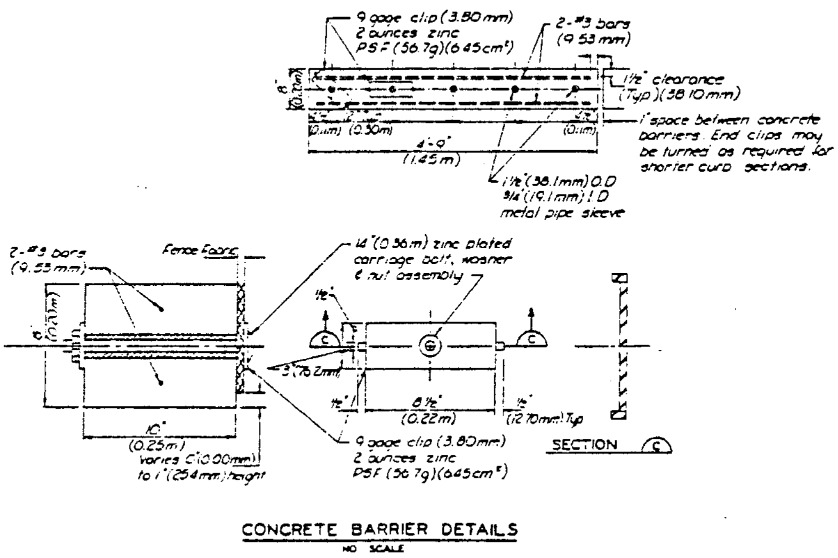
The H-section line post configuration is best utilized as an end post when the requirement is for additional strength from an intermediate fence post. It has two ounces of zinc per square foot and provides excellent bending strength. Recommendations are with the C-section roll formed from steel 2.25" x 1.70" with a minimum theoretical bending strength of 314 pounds under 6 foot cantilever load.

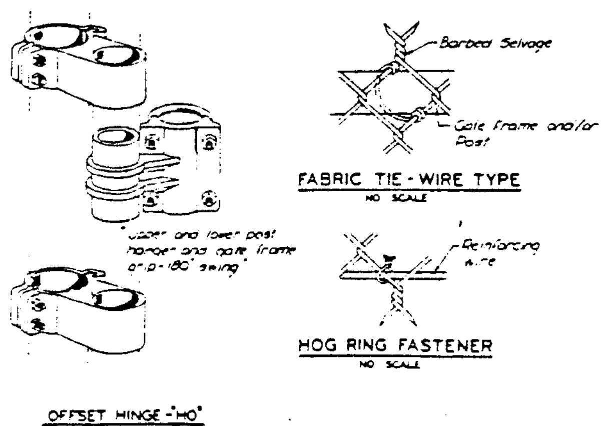
14.2.4 Terminal Posts

This design (Figure 14.2 and 14.3) offers an excellent deterrent to vandalism. The sections are designed with chain link fabric weaving into the post. This eliminates nuts, bolts, and clamps. This construction has a two ounce per square foot zinc coating and unlike round posts, is self-draining and self-ventilating, thus eliminating rust.

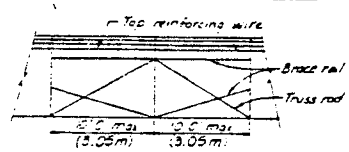
Post settings for line and terminal posts dictate the need for approximately 36 inches of metal below grade.







POST	
USE AND SECTION	FABRIC [illegible] WIDE & OVER (2.1 m)
CORNER, END & PULL POSTS TUBULAR - ROUND	2.875" OD 5.79 #/LF (73 mm) (2.63 kg)/(0.30m)
SQUARE	2.5" SQ. 5.70 #/LF (64 mm) (2.59 kg)/(0.30m)
LINE POST	
H-SECTION	2.25" X 1.70" 4.10 #/LF 57 mm) 43 mm) (1.86 kg)/(0.30m)
C SECTION	2.25" X 1.70" 2.73 #/LF 57 mm) 43 mm) (1.24 kg)/(0.30m)
TOP RAIL - BRACE RAIL TUBULAR - ROUND	1 2/3" OD 2.27 #/LF 42 mm) (1.03 kg)/(0.30m)
CHANNEL	1 5/8" X 1¼" 1.35 #/LF 41 mm) 32 mm) (0.61 kg)/(0.30m)



TYPICAL FENCE POST

Fabric fastened to pull post by stretcher bars & bar bands. Install wherever unbraced length exceeds 500 feet (152.40m)

FIGURE 14-2. Illustration of Fence Details
Courtesy of U.S. Steel Corp/Cyclone Fence

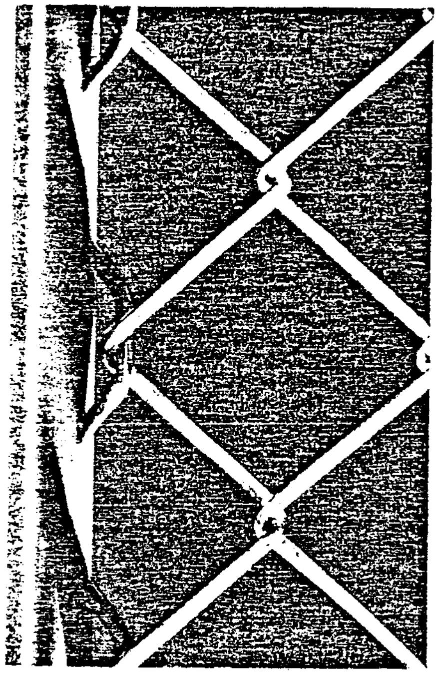


FIGURE 14-3. "No Bolt" Terminal Post
Picture Courtesy of U.S. Steel Corp.
Cyclone Fence

Concrete footings should be 10 x 36 inches for line posts and 12 x 36 inches for terminals. In some cases C-section line posts may be mechanically driven into the earth in lieu of concrete. Economic benefits from drive post construction can be realized on initial installation as well as future maintenance. In drive post construction a wedging action occurs at the bottom when the post is impacted. The bottom opens and can spread up to 1/4 in. depending on the type of soil strata. This causes a more compact and tighter set in the surrounding soil resulting in less movement. Futhermore, this method eliminates "mushrooming" at the top of the post which would hamper the use of the top caps and fittings in the case of slide or swing gates.

Cost data for fences are shown in the following table.

TABLE 14-1

RELATIVE COST OF 2 IN. DIAMOND MESH FENCE
(less barbed wired)

Line Fence	Fence Gauge	Fence coatings in oz/ft^2	Price per ft.
9 ft.	6	Zinc (2 oz.)	$19.00
9 ft.	6	Aluminum (0.4 oz.)	19.00
9 ft.	6	Zinc (1.2 oz.)	18.00
9 ft.	9	Zinc (2 oz.)	14.00
9 ft.	9	Aluminum (0.4 oz.)	14.00
9 ft.	9	Zinc (1.2 oz.)	13.50
10 ft.	6	Zinc (2 oz.)	20.00
10 ft.	6	Aluminum (0.4 oz.)	20.00
10 ft.	6	Zinc (1.2 oz.)	18.75
10 ft.	9	Zinc (2 oz.)	15.00
10 ft.	9	Aluminum (0.4 oz.)	15.00
10 ft.	9	Zinc (1.2 oz.)	14.50

Prices are calculated estimates and may vary depending on geographical location. All prices listed include installation. Terminal posts are included in the cost unit price per foot.

14.2.5 Fence Toppings

To gain added security it has been a practice to install up to three strands of barbed wire above the fixed fence structure. The three strand protection can, however, be easily surmounted by an individual having specific "intent" to enter.

In 1957 the U.S. Army Engineer School in Europe conducted an engineering evaluation of the "Barbed Tape Concertina" (BTC) as developed by the Germans. It was decided that the BTC design warranted modification and improvement since it could be crossed in 5 to 10 seconds without the use of breaching aids.

An improvement was developed in 1970 which was known as "General Purpose Barbed Tape Obstacle" (GBPTO) (Figure 14-4).

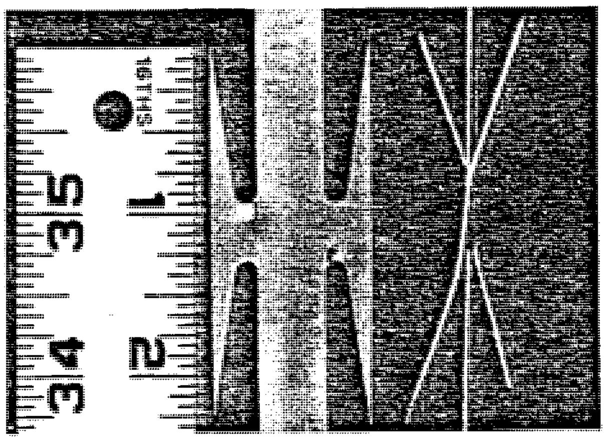


FIGURE 14-4. Barb Configuration
(GPBTO Type II)
(Man Barrier Corporation Photograph)

The barbed material as illustrated is manufactured by the Man Barrier Corporation, Seymour, CT. The design employs a nickel-chrome stainless steel composition which provides protection against galvanic degradation. The austenitic structure allows the material to be hardened to spring quality, and having a brushed finish it minimizes interference with active sensor systems (e.g., microwave and infrared detectors).

Type II GPBTO as depicted in Figures 14-5 and 14-6 was U.S. Army tested for the Department of Defense Nuclear Agency. These tests substantiated its impregnability and total cost effectiveness.

It was confirmed that the material when positioned on the top of a chain link fence is "impossible to cross without the use of breaching aids" and "cannot be crossed with simple breaching aids." The only possible crossing technique involved

FIGURE 14-5.
Single Bracket Mounting

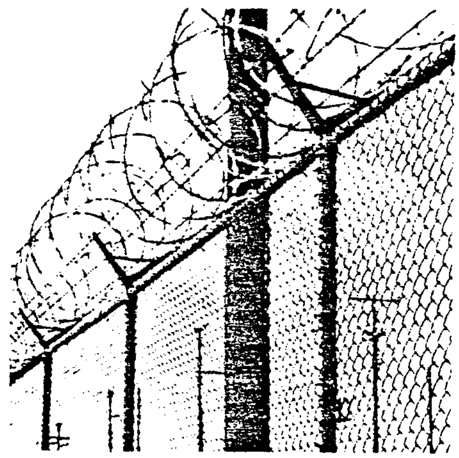


FIGURE 14-6.
Double Bracket Mounting

(Man Barrier Corporation Photographs)

crews of four or more men using complicated and sophisticated breaching aids. Rolls of the material positioned within the confines of the fence further deter, complicate, and restrict uninjured entry into private property. (Figures 14-7 and 14-8.)

Table 14-2 illustrates the configurations of the four arrays and presents the relative cost of using either GPBTO or BTC, respectively, in each array.

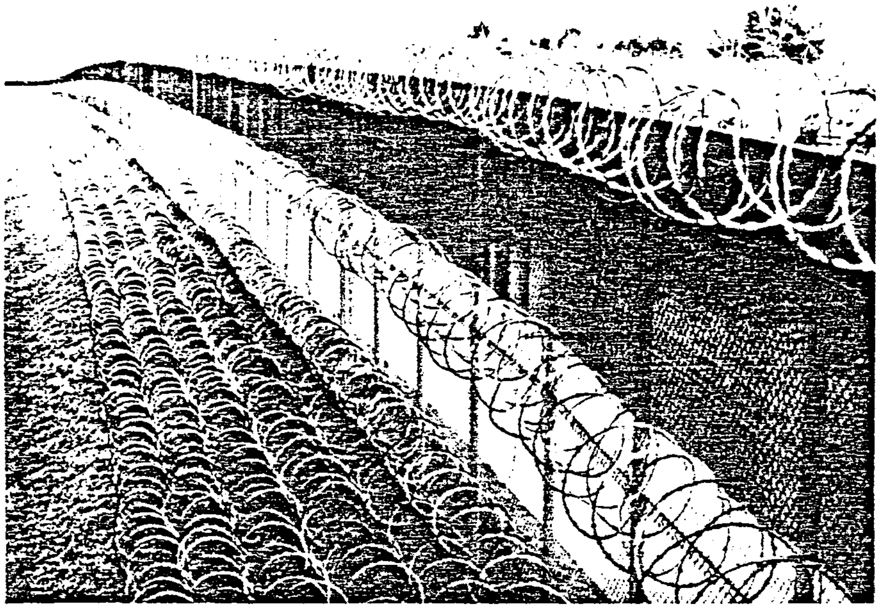


FIGURE 14-7. GPBTO Type II - on top 8 ft. chain link fence, middle loop and six bottom loops

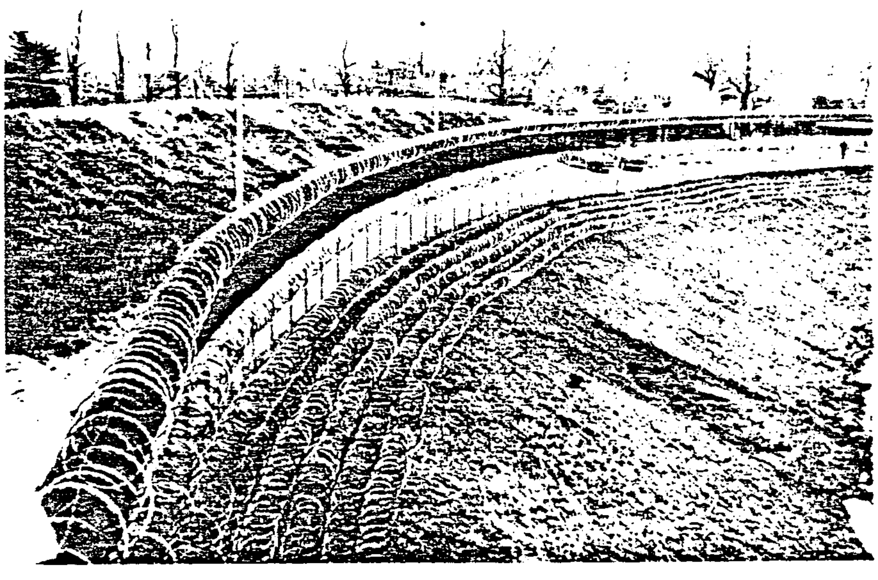
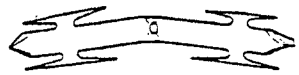
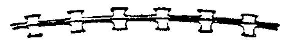
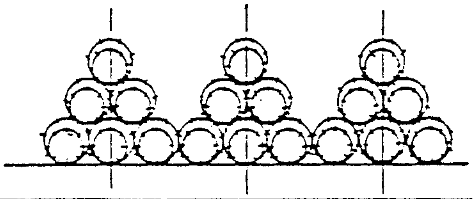
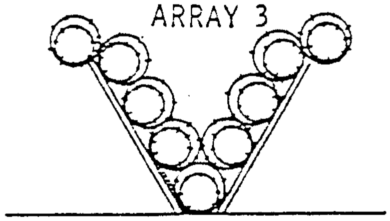
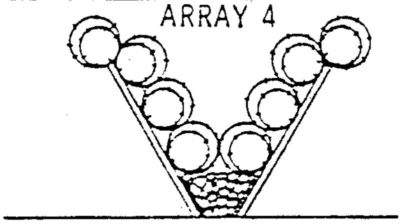


FIGURE 14-8. GPBTO Type II

(Man Barrier Corporation Photographs)

<u>TABLE 14-2</u>

RELATIVE COST OF GPBTO AND BTC

	WITH GPBTO 	WITH BTC 
ARRAY 1 	* $115/Meter ($35/foot)	$46/Meter ($14/foot)
ARRAY 2 	$247/Meter ($75/foot)	* $112/Meter ($34/foot)
ARRAY 3 	* $293/Meter ($89/foot)	$224/Meter ($68/foot)
ARRAY 4 	$378/Meter ($115/foot)	* $319/Meter ($97/foot)

* INSTALLED AND TESTED

Table Prepared By Man Barrier Corporation.

Average costs for GPBTO and BTC less installation and without above array configurations are as follows:

Type II GPBTO (double coil)	$4.00/ft.
Type III GPBTO (single coil)	.80/ft.
Barbed Tape Concertina	.60/ft.

14.3 Entrance and Egress

14.3.1 The "Total Systems Concept"

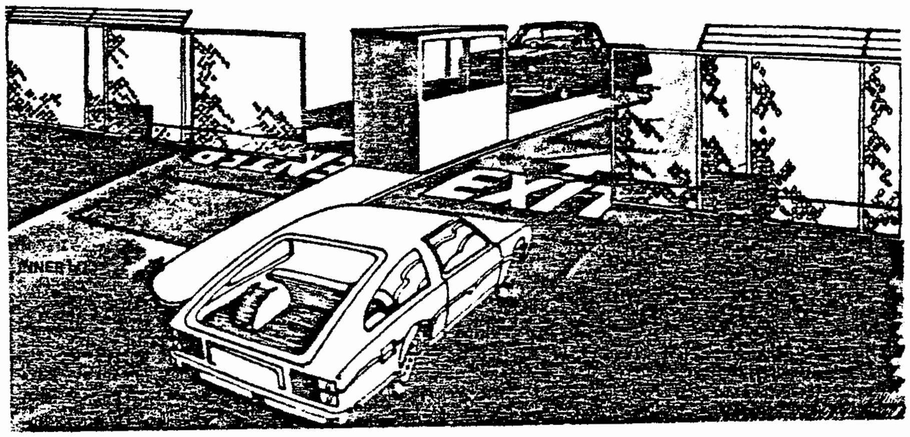


FIGURE 14-9. The "Total Systems" Approach
(Picture Courtesy Stanley Vemco Corp.,
Detroit, Michigan)

Above is the total systems approach for perimeter control. Shown are two bi-parting sliding gates each with its own automatic operator.

Entrance:

As the vehicle approaches the gate entrance (Figure 14.9) the driver places a coded card into the card reader. This transmits an impulse to actuate the electric operator which opens the gate. A radio transmitter or keyswitch may be used instead of a card reader or the gate can be opened via a pushbutton station from a guardhouse at the site. As the vehicle passes through the opening, passing over the "inner loop," an impulse is transmitted to hold the gate in the open position. When the loop has been cleared the timer, after a pre-set period, sends an impulse to the gate operator to "close the gate." Should the gate be closing as the vehicle reaches the loop area, the gate reverses to the open position and the timer is automatically reset for another full-time cycle.

Egress:

From inside the fence line the vehicle approaches the gate and passess over the inner loop transmitting an impulse to actuate the gate operator and opens the exit gate. For controlled exit, a card reader, keyswitch, radio control, or pushbutton (located within a guardhouse) can again be utilized. The inner (exit) loop may not be needed if the exit is 24-hour guard controlled. As the vehicle passes over the outer loop the gate opens. When the vehicle clears the outer loop, the gate closes.

Within the "total systems concept," security guards need not be present 24 hours a day at the gate entrance. Drivers who make regular stops at the facility would have pre-designated cards. Non-regular stop drivers would simply stop at the main guard station and could either attain a temporary card or the guard would open the gate using the standard three-button switch.

Stanley Vemco Corporation currently markets three models of automatic slide gate operators:

Model ASJCB

Typical Use: Medium-duty commercial installations

Features:

- 1/3 or 1/2 H.P., 115V or 230V single-phase motors.
- Single-belt, sprocket motor speed reduction
- #41 output, idler sprocket and roller chain

Cost: $2,300 (includes 1/2 H.P. motor, installation and mounting on concrete pad)

Model ASJH

Typical Use: Heavy duty, high frequency, commercial and industrial installations

Features:

- 1/2, 1/3, or 1 H.P. motors (available in all standard voltages)
- Double-belt, chain and sprocket motor speed reduction.
- #40 output sprocket, idler sprocket and dive roller chain on 1/2 and 3/4 H.P. models
- #50 output sprocket, idler sprocket and drive roller chain on 1 H.P. version.
- MRD Timer (limits run time of operator to maximum or 90 seconds in any one direction. Prevents excessive wear on integral operator components in the

event the gate becomes obstructed during the open or close cycles. Also delays reversal of gate 1.5 seconds when signaled from open button or safety device reducing the shock load on both the gate and operator.

- Interface control for Remotely Located Single and Three-Button Stations. (Gives maximum remote station capability of up to six miles. Package is pre-wired in NEMA 3R rain-tight enclosure.)
- Includes Standard pushbutton switch

Cost: $2,500 (includes 1/2 H.P. motor installation, mounting on 8-inch thick, 3 ft.^{2} concrete pad. Does not include electrical installation.)

Model SJGFT

Typical Use: Heavy duty, oversized installations

Features:

- 2 H.P., 230V, 460V, and 550V three-phase motor
- 32:1 worm gear and "T" third reduction heavy-duty construction throughout
- Roller lever type limits on gates over 50 ft. wide; standard rotary limits under 50 ft.
- Torque limiter
- Hand crank for manual operation
- #50 output idler sprockets and roller chain

Cost: $7,500 (includes 2 H.P. motor; this unit is used with specially fabricated heavy duty gates).

Should a swing gate be desired, the following operator model is recommended:

<u>Model MSG</u>

Typical Use: Medium-duty commercial installations

Features:

- 1/3 H.P. 115V single-phase motor
- Contactor starter
- Gear head motor, double belt final drive
- Will receive three-button and single-button type controls, keyswitch and radio control accessories as standard

Cost: $3,000 (includes 1/3 H.P. motor installation and mounting on concrete pad).

<u>NOTE</u>: One operator is needed for each gate

The price listed above is for a 10 ft. gate leaf. Tables 14.3 and 14.4 list recommended capacities for slide and swing gates.

<u>TABLE 14.3</u> Recommended Capacities of Slide Gate Models ASJCB, ASJH and SJGFT.

Model	Motor	Gate Travel Speed Per Minute	Maximum Gate Weight	Maximum Overhead Gate Opening	Maximum Cantilever Gate Opening	Maximum Roller/V-track Gate Opening	Shipping Weight	Frequency of use (Complete cycles/hour)
ASJCB 3	1/3 HP	57 ft.	550 lbs.	20 ft.	12 ft.	16 ft.	185 lbs.	20
ASJCB 2	1/2 HP	57 ft.	700 lbs.	20 ft.	12 ft.	16 ft.	190 lbs.	20
ASJH 2	1/2 HP	60 ft.	900 lbs.	36 ft.	20 ft.	26 ft.	205 lbs.	30
ASJH 4	3/4 HP	60 ft.	1200 lbs.	46 ft.	26 ft.	36 ft.	210 lbs.	30
ASJH 1	1 HP	60 ft.	1500 lbs.	58 ft.	32 ft.	48 ft.	230 lbs.	30
SJGFT	2 HP	45 ft.	Designed for large roller type gates.				280 lbs.	25

Tables 14.3 and 14.4 Prepared by Stanley Vemco Corporation.

TABLE 14.4 Recommended Capacities of Swing Gate Model MSG

Model	Maximum Gate Leaf	Seconds to Open Gate	Maximum Gate Weight	Shipping Weight	Frequency of use (Complete cycle/hour)
MSG	14 ft.	12 to 15 secs.	500 lbs.	180 lbs.	15

Figures 14-10, 14-11 and 14-12 illustrate complete fence specifications. Figure 14-10 shows the Standard Cantilever Slide Gate with malleable iron rollers, supports, mesh fabric, guide posts, etc. Note that the maximum design standard shown is 24 ft. for single and 48 ft. for double cantilever gates.

Figure 14-11 illustrates a single swing gate with a welded frame, lock keeper, lock keeper guide, posts, hinges, etc. This type fence configuration would be used inside the facility for personnel passage via pathways, etc.

Figure 14-12 illustrates the double swing gates with welded frames and surmounted barb wire; lock keepers, upper and lower forks, posts, hinges, etc. Note that the three strand method of barb wire placement has been proven ineffective in keeping out intruders without breaching aids and with minimal "malicious intent." Barbed tape configurations are recommended as mentioned earlier (Refer to figures 14-5 and 14-6).

Table 14.5 illustrates estimated cost data for the three fence gates listed. It is suggested that the heaviest fence gauge be used where appropriate since the gate cost is the same for either zinc (2 oz. or 1.2 oz.) or aluminum (0.4 oz.).

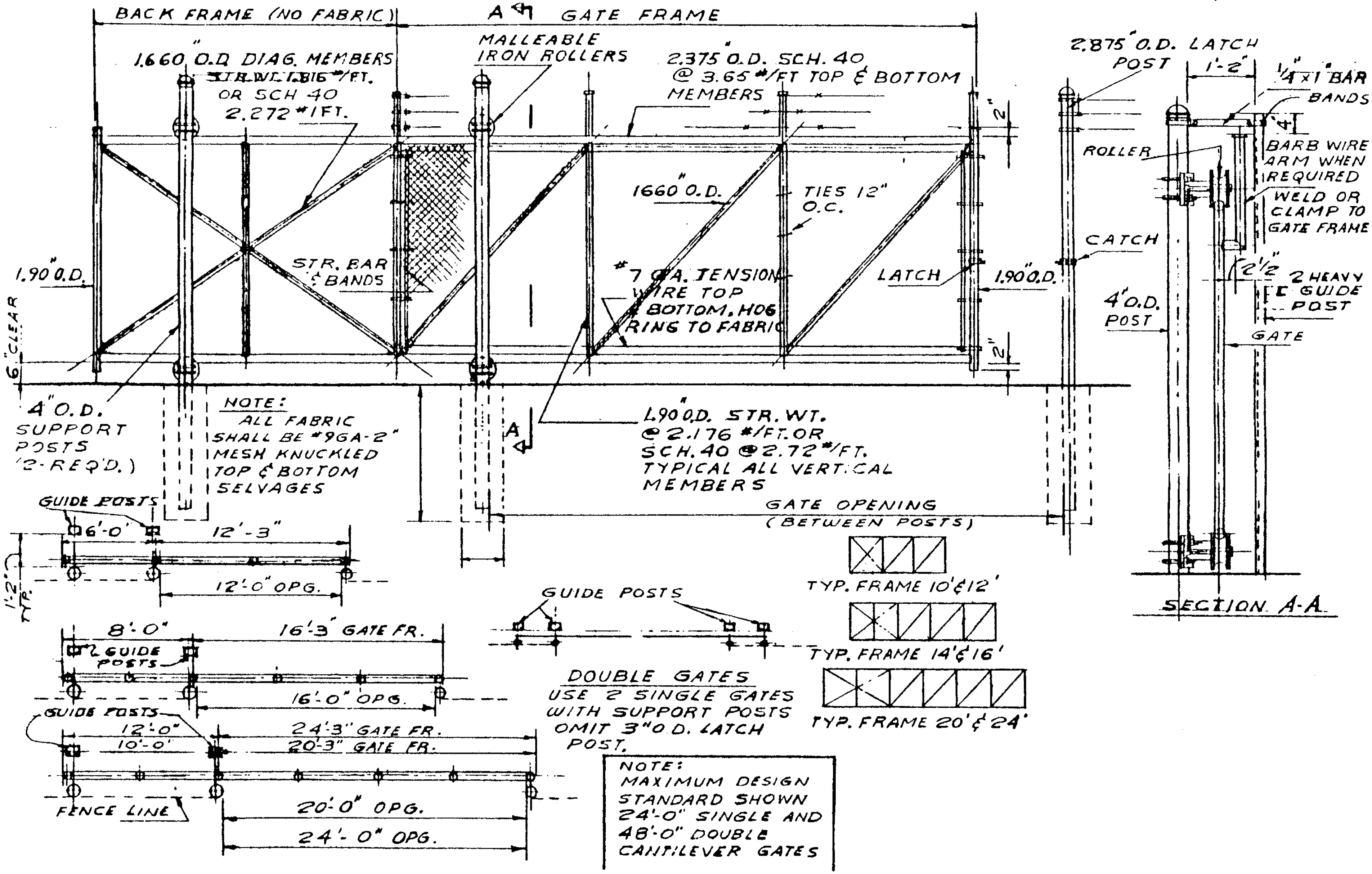


FIGURE 14-10. Standard Cantilever Slide Gates Illustration Courtesy of United States Steel Corporation

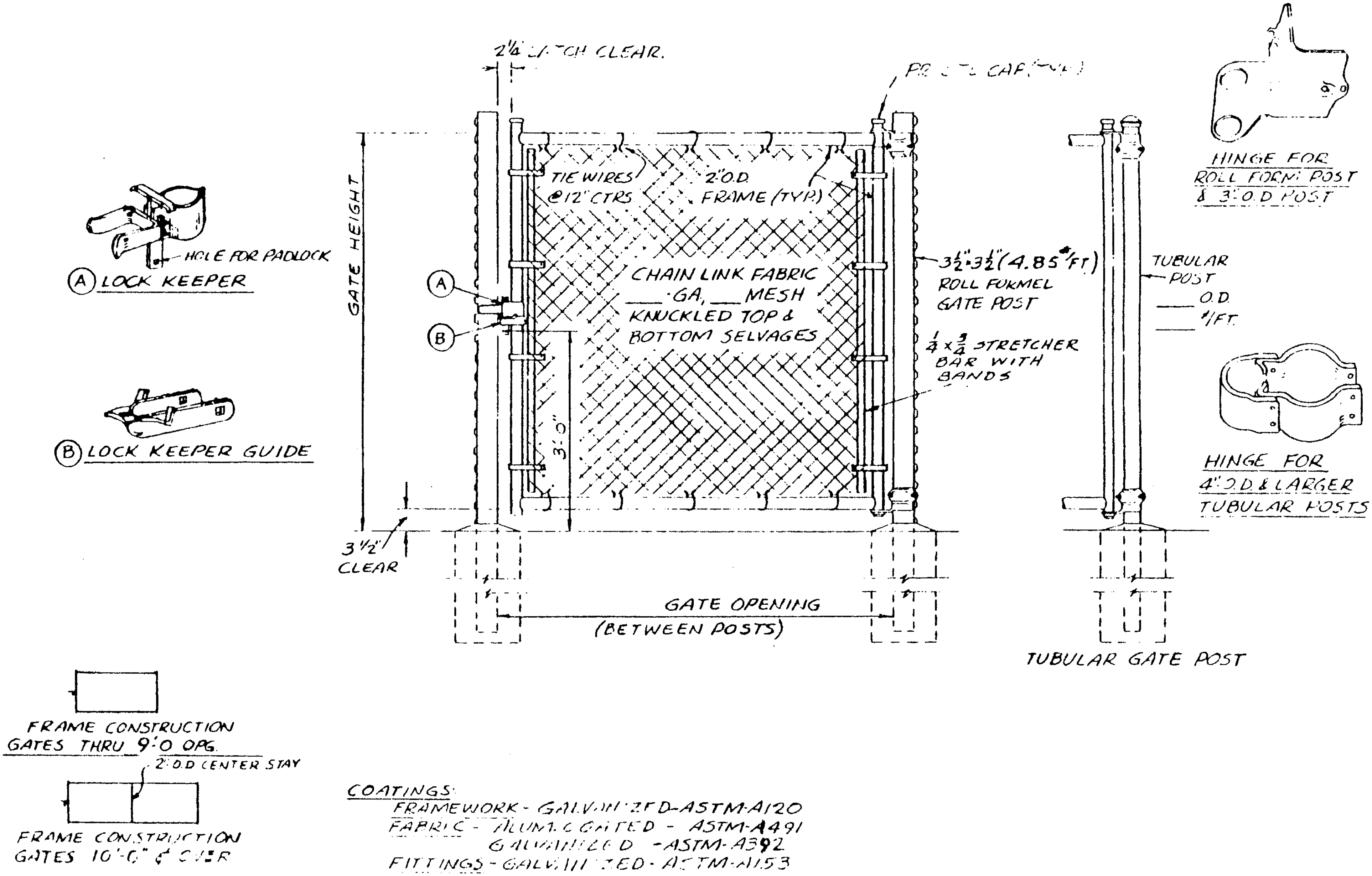


FIGURE 14-11. Single Swing Gate with Welded Frame
Illustration Courtesy of United States Steel Corporation

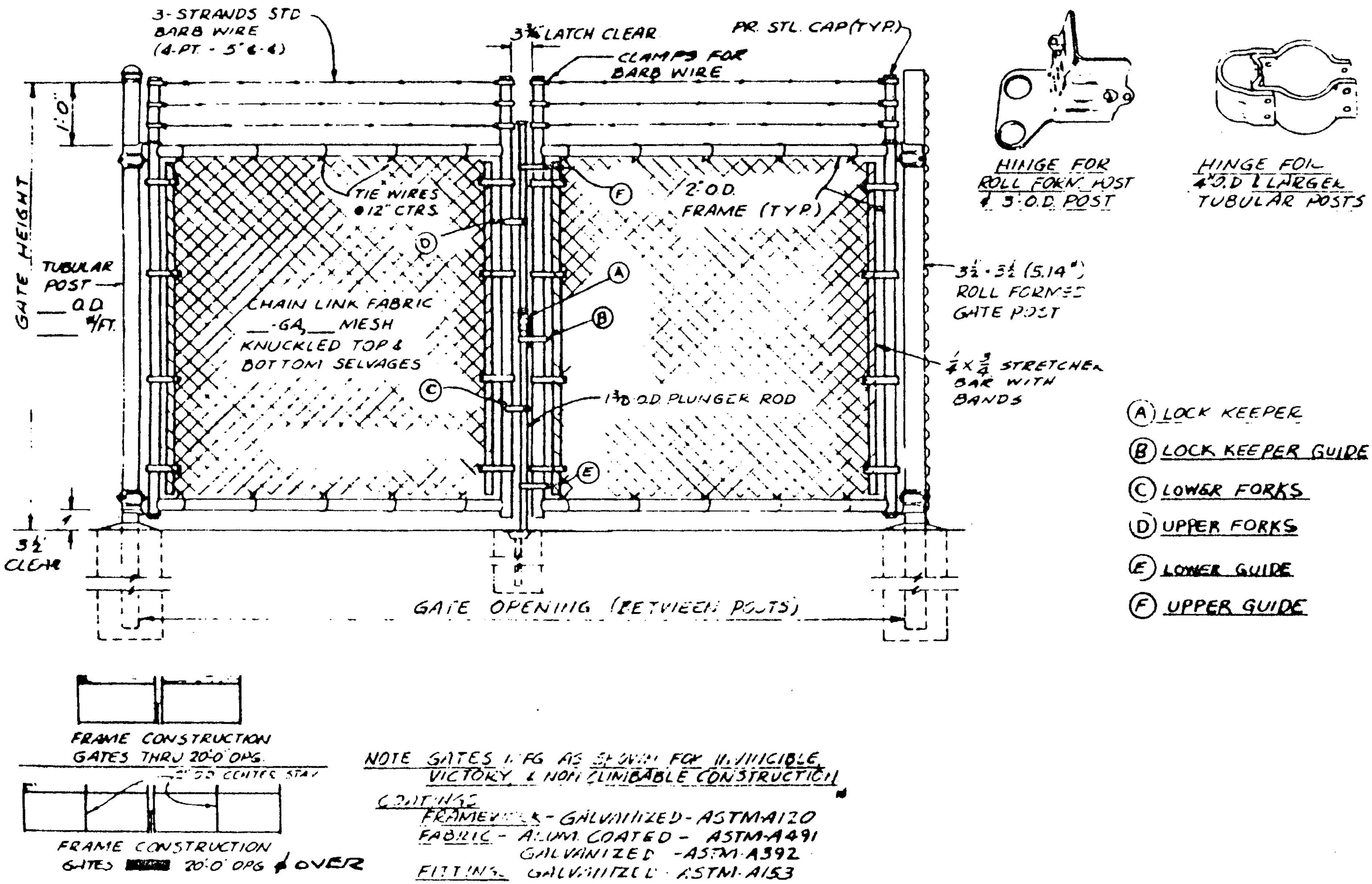


FIGURE 14-12. Double Swing Gates with Welded Frames
Illustration Courtesy of United States
Steel Corporation

TABLE 14.5

SLIDE AND SWING GATE ESTIMATED COST DATA
(Less barbed-wire)

Fence Height	Fence Gauge	Slide Gate Gate Opening	Single Swing Gate Opening	Double Swing Gate Opening	Estimated Cost	See Figure Number
9 ft.	9	20 ft.			$3,000	14.8
9 ft.	9		4 ft.		200	14.9
9 ft.	9			20 ft.	600	14.10
10 ft.	9	20 ft.			3,100	14.8
10 ft.	9		4 ft.		225	14.9
10 ft.	9			20 ft.	650	14.10

All prices include installation.

Card Readers and Intercoms

Card readers used in conjunction with either a swing or slide gate fence as mentioned earlier makes for one of the best and most efficient methods for entry (Figure 14-13).

Intercom systems may be used in conjunction with card readers throughout a facility and models having keyswitch capabilities are suggested for use at gate entrances (Figure 14-14).

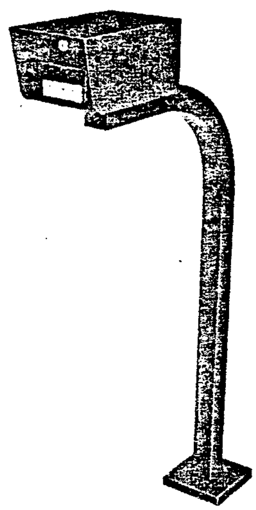


FIGURE 14-13. Card Reader Four-Period Card Control Unit on Gooseneck Stand permits access through the gate only to authorized card holders. The reader has four different codes.

Illustrations Courtesy Stanley Vemco Corporation

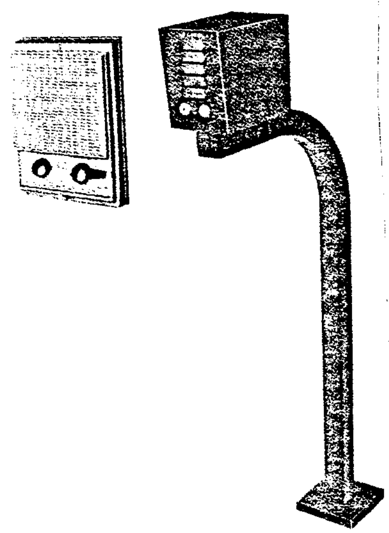


FIGURE 14-14. Intercom Call Station (on gooseneck stand) ffers point-to-point intercommunication, a bell pushbutton, bell signal, and indoor call station. There is also a keyswitch in the face of the station for local gate control.

The average cost for a four-period card reader, including installation and mounting on a concrete pad or in a footing, is $600.00. Again, this price is less any electrical installation. Cards are estimated at $1.50 each.

14.4 Closed Circuit Television Surveillance

Up until a decade ago or so man had to rely on his own eyes to visually detect and access threats to security facilities. Exits, entrances, storage areas, etc., had to be observed by individual guards. There was no practical way to extend man's vision to site at which he was not physically present.

In a closed circuit television (CCTV) system many different cameras can be seen on a single monitor. Typically a security guard may wish to observe several different entrances and exits, plus certain critical loading areas, etc. Using a "video switch" each of the cameras' views are seen in a designated sequence for a selected time period from one second to a minute or more. In some installations it may be desirable for several different people spacially separated to observe the same TV picture. In this case it is possible to route the signal from a single CCTV camera to several different monitors. With CCTV systems it is not only possible to see things beyond the reach of human eyesight, but also to record these events for later analysis. This capacity has proved invaluable in securing applications where it is often necessary to document evidence of wrongdoing.

14.4.1 Scanning Cameras

For some applications it may be desirable to have the CCTV camera focused on a single scene--a door opening, loading platform, dock area, pumping station, etc. In other applications, however, it may be desirable to have the camera scan an area. There are a variety of motorized pan and tilt combinations which permit view within a 350 degree horizontal and 90 degree vertical arc of the camera mounting. In many instances the camera will continue to pan right and left in a designated arc, unless overridden via manual control.

14.4.2 Zoom Lenses

Remote controlled zoom lenses permit the operator to not only stop the camera at one point in the arc but also to "zoom in" on a small area to observe particular details. A zoom lens maintains the ability to keep an object or scene in focus, while changing its focal length, thus magnifying distant scenes analogous to a telephoto lens. In addition, zoom lenses are often equipped with remotely controlled or automatic irises which allow for compensation of differences in lighting conditions during the daytime, permitting opening and closing to provide the best possible picture.

14.4.3 CCTV - Near and Complete Darkness

The lens (or eye) of the CCTV camera has one other advantage over the human eye--it can see in the dark.*

---

*Not absolute darkness. Nothing can see in 100% darkness, but in nearly all commercial or industrial applications some small amount of illumination, if only a trace of moonlight, is available. This petite quantity of light is enough for specially designed CCTV cameras.

Lighting conditions can range from as much as 10,000 ft. candles of illumination in full sunlight to 0.001 ft. candles in partial moonlight. Specially designed cameras referred to as "LLLTV"--Low Light Level TV cameras--are capable of seeing within the above mentioned ranges.

By using infrared technology, objects invisible to the human eye can be clearly photographed. A storage area or plant exterior can be "lit" by infrared lamps. The illumination is invisible to the human eye but clearly visible to a silicon diode-type CCTV camera whose response is in the red region of the light spectrum. Incandescent or sodium vapor infrared spectrum lighting systems can be installed in warehouse areas, exterior loading/unloading areas, doorways, etc. These lamps project infrared radiation to the area and the radiation reflection is observed by the camera and displayed on the CCTV monitor as a near-daylight picture. The nighttime vision of CCTV is of obvious importance in security applications since the majority of all thefts, burglaries and vandalism occur during nighttime hours.

There are specially designed exterior housings to protect CCTV cameras against variations in weather conditions through the application of blower fans, heating units, etc. Some cameras are equipped with windshield washers and wipers to keep the viewing lens clean of grime and dust. Exterior cameras can be mounted practically anywhere--on roof tops, lighting towers, and other strategic locations to gain the best viewing advantage.

Listed below are some current models of CCTV units.

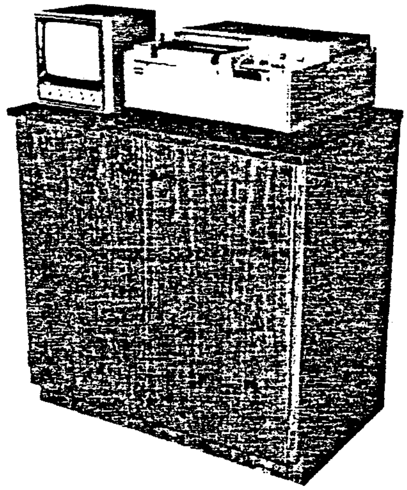


FIGURE 14-15.
Photoguard TV-11 CCTV System
(Illustration Courtesy Mosler Systems)

The Photoguard TV-11 CCTV System (Figure 14-15) manufactured by Mosler Systems, Wayne, New Jersey, provides live action viewing of transactions, instant replay, low cost operations using video tape recording, and time/date display. Photoguard can also be used with an instant camera to provide hard-copy photoprints of any frame selected. Additional capabilities include sequencing for up to 10 cameras, reusable magnetic tape, optional time and date recording, camera resolution of more than 600 lines, unique control center for hands off operation and 9, 12, or 17 inch TV monitors. The estimated cost less installation is $5,300.00 (7/80).

The new CCTV system (Figure 14-16) introduced by the HB&W Company is designed for nighttime surveillance and can scan areas of total darkness up to 120 feet either indoors or

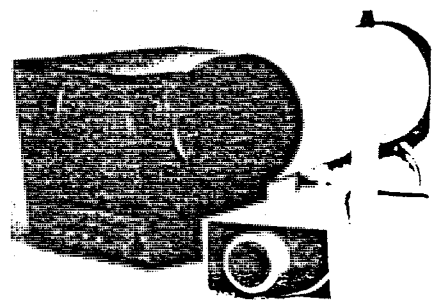


FIGURE 14-16. Infrared CCTV
(Illustration - Courtesy HB&W Company)

out. The video monitor projects the scanned image with a detail resolution of 700 lines per inch (twice that of home TV's). The cost of this particular system falls within the range of the Photoguard TV-11.

There are numerous CCTV systems on the market today. Prices of models vary depending upon the number of cameras, monitors, Cathode Ray Tubes (CRT's) used. To list all the models would be sesquipedal. Specific CCTV systems are better discussed as part of the total security system in combination with advanced detection systems discussed later in this report.

Figure 14-17 illustrates various cameras, monitors, and loop configurations for different kinds of commercial and industrial facilities. Naturally, each of these layouts could have been optimized with additional cameras and/or monitors. The layouts illustrated are simply graphic illustrations of three typical CCTV installations.

Poorly selected and installed CCTV systems can sometimes be worse than no system at all, since they may engender a sense

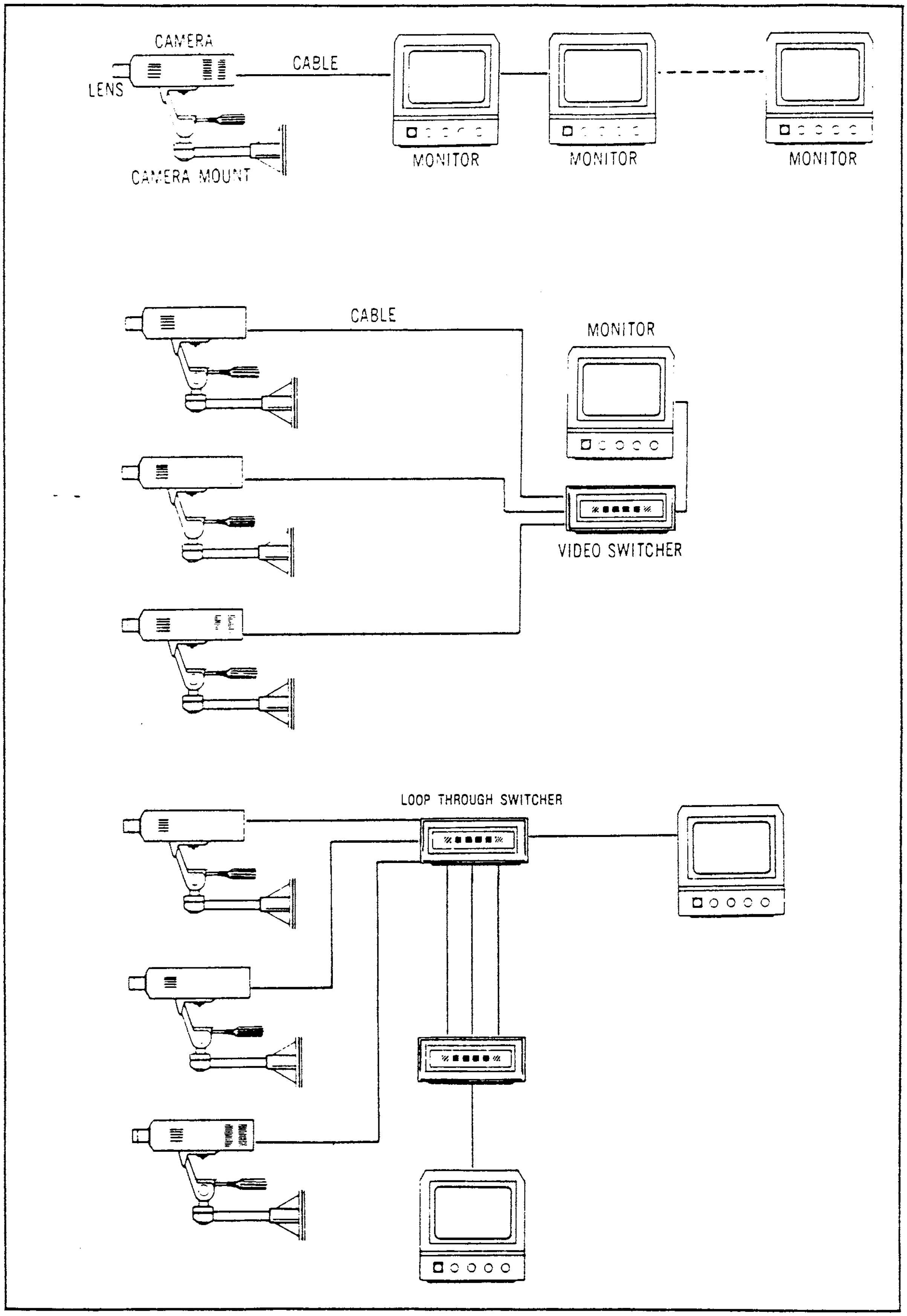


FIGURE 14-17. Camera and Monitor Configurations
Illustration--Courtesy ADT Security Systems

of security which might prove illusory during an actual criminal instrusion. The proper CCTV system chosen should provide a 24-hour a day surveillance capability.

14.5 Lighting

14.5.1 Lamp Considerations

In designing a lighting system for any facility, lamp selection will have a significant impact on the performance and cost. Depending upon the application requirements, any one of three high intensity discharge (H.I.D.) lamps may be used: High Pressure Sodium, Metal Halide, or Mercury Vapor. The characteristics of these sources may vary widely. The lamp performance characteristics (Table 14-6) provides a comparison of these traits. The data represents selected lamps from three manufacturers.

There are certain cases where color rendering characteristics of a light source impact heavily on the selection of a suitable lighting system. (Examples would be the preference of metal halide lamps for TV coverage or areas where color matching of certain items is important.) Although most objects appear to be steadily lighted when seen under H.I.D. sources, high speed machinery or other rapidly moving objects may appear to stand still or slow due to stroboscopic effect or "flickering" (H.I.D. lamps operating on alternating current actually go about 120 times a second, at 60 cycles). Metal halide lamps are least effected, followed by phosphor coated mercury vapor

TABLE 14-6

HI-TEK COMPANY INC. LAMP PERFORMANCE CHARACTERISTICS

LAMP TYPE	WATTAGE	START-UP TIME (MINUTES)[1]	RESTRIKE TIME (MINUTES)[2]	INITIAL LUMENS PER WATT	AVERAGE RATED LIFE (HOURS)[3]	INITIAL LUMEN RATING	MEAN LUMEN RATING
HIGH PRESSURE SODIUM CLEAR LAMPS	50	3-4	1	66	24.000	3.300	2.970
	70	3-4	1	82 86	24 000	5.800	5.220
	100	3-4	1	95	24.000	9.500	8.550
	150	3-4	1	106.7	24.000	16.000	14.400
	200	3-4	1	110	24.000	22.000	19.800
	250	3-4	1	110	24.000	27.500	24.750
	250S	3-4	1	120	24.000	30.000	27.000
	310	3-4	1	119 4	24.000	37.000	33.300
	400	3-4	1	125	24.000	50.000	45.000
	1000	3-4	1	140	24.000	140.000	126.000
METAL HALIDE CLEAR LAMPS	175	2	10	80	7.500	14.000	10.800
	250	2	10	82	10.000	20.500	17.000
	400	2	10	85	20.000	34.000	25.600
	1000	4	10-15	110	10.000	110.000	88.000
	1500	5	10-15	103.3	3.000	155.000	140.000
METAL HALIDE PHOSPHOR COATED LAMPS	175	2	10	80	7.500	14.000	10.200
	250	2	10	82	10.000	20.500	16.000
	400	2	10	85	20.000	34.000	24.600
	1000	4	10-15	105	10,000	105.000	83.000
SUPER METAL HALIDE CLEAR LAMPS	175HORIZ	2	10	85 7	10.000	15.000	12.000
	400HORIZ	2	10	100	20.000	40.000	32.000
	400VERT	2	10	100	15.000	40.000	32.000
	1000VERT	4	10-15	125	10.000	125.000	100.000
SUPER METAL HALIDE PHOSPHOR COATED LAMPS	175HORIZ	2	10	85.7	10.000	15.000	11.300
	400HORIZ	2	10	100	20.000	40.000	31.000
	400VERT	2	10	100	15.000	40.000	31.000
	1000VERT	4	10-15	125	10.000	125.000	95.800
MERCURY VAPOR DELUXE WHITE	100	5-7	3-6	45	24.000	4.500	3.650
	175	5-7	3-6	49.2	24.000	8.600	7.650
	250	5-7	3-6	52	24.000	13.000	11.000
	400	5-7	3-6	57.5	24.000	23.000	20.100
	1000	5-7	3-6	63	24.000	63.000	48.500

[1] Start up time: Time from initial energizing to 80% of full output.

[2] Restrike time: Time to restrike after momentary power interruptions.

[3] Average rated life: Number of burning hours at which 50% of a group fail, based on a 10 hour/start.

and high pressure sodium. The stroboscopic effect can be eliminated by operating fixtures on separate phases of a three-phase system.

When selecting a light source for a given application, certain general economic guidelines can be applied. It would be desirable to select the largest wattage lamp available and mount the fixtures as high as possible. This should result in the least expensive system with the best uniformity. High pressure sodium usually provides the most economical system based upon total owning and operating costs. Metal halide and mercury vapor are next in order of system costs.

14.5.2 Outdoor Lighting Design

Lighting design in today's market dictates the need for a complete analysis to conserve energy usage, and lower installation and owning costs. There are lighting companies which presently run computer assisted design services for just this purpose. Hi/Tek Corporation markets their Hi/Tek ECON program which is designed to provide a relative economic comparison and financial analysis of up to four different lighting systems including an existing system if desired. A complete comparison of initial costs, operating costs and total owning costs is made to determine the relative cost relationships between systems. All systems are then compared to the lowest initial cost system to determine payback periods, return on investment and benefit/cost ratios.

Most H.I.D. lamps are designed to be used in any burning position with little or no effect on light output. However, some metal halide lamps are greatly effected by off-vertical burning. Applications using metal halide lamps may be less than satisfactory if lumen correction factors are not employed. In general, it is a good practice to aim the luminaire two-thirds of the distance across the area to be lighted. Also, to insure good visual comfort the floodlight should be aimed at least 30° below horizontal; if this cannot be done the mounting height should be increased. Generally good uniformity can be expected if luminaires are aimed so that the edge of the beam of a given fixture intersects the aiming of the adjacent fixture.

14.5.3 Floodlight Beam Spread

For security lighting beams should overlap by one-half (Figure 14-18). This is accomplished by keeping the spacing between the fixtures less than one-half the diameter in feet of the beam on the surface.

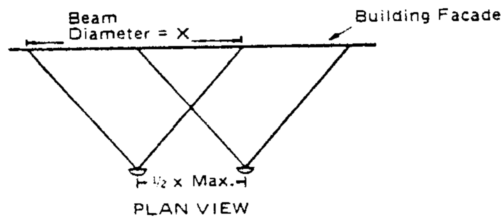


FIGURE 14-18.
BEAM OVERLAP CRITERIA
(Illustration Courtesy Hi-Tek Co., Inc.)

When the luminaire is not aimed perpendicular to the surface being lighted as shown in Figure 14-19, the horizontal beam dimension "H" may be determined from Table 14-7 (Beam Projection Chart).

Table 14-7 is used in determining the size (in feet) of a floodlight beam when the luminaire is aimed perpendicular to the surface being lighted as shown in Figure 14-20. The horizontal beam dimension "H" and vertical beam dimension "V" for varying projection distances "P" are tabulated above.

For area lighting, horizontal beam dimensions may also be determined from Table 14-7. Generally, if the width of the area is small compared to the spacing between fixtures, twin beams should be used. If the width of the area is equal to or greater

<u>TABLE 14-7</u>

BEAM PROJECTION CHART

Beam Spread in Degrees Hor. (H) or Vert. (V)	BEAM DIMENSION IN FEET PROJECTION DISTANCE P (Feet)																			
	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
10°	0 9	1 7	2 6	3 5	4 4	5 2	6 1	7 0	7 8	8 7	9 6	10	11	12	13	14	15	15 5	16	17
20°	1 8	3 5	5 3	7 0	8 8	10	12	14	16	18	19	21	23	25	26	28	30	32	33	35
30°	2 7	5 4	8 1	11	13	16	19	21	24	27	30	32	35	37	40	43	45	48	51	54
40°	3 6	7 2	11	14	18	22	25	29	33	36	40	44	47	51	55	58	62	65	69	72
50°	4 6	9 3	14	19	23	28	33	37	42	46	51	56	60	65	70	74	79	84	88	93
60°	5 7	12	17	23	29	34	40	46	52	57	63	69	75	80	86	92	97	103	109	115
70°	7 0	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112	119	126	133	140
80°	8 4	17	25	34	42	50	59	67	75	84	92	101	109	118	126	134	143	151	160	168
90°	10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	200
100°	12	24	36	48	60	72	84	95	107	119	131	143	155	167	179	191	203	215	227	239
110°		29	43	57	71	86	100	114	129	143	157	172	186	200	214	229	243	257	272	286
120°	17	35	52	69	87	104	121	139	156	173	191	208	226	243	260	278	295	312	330	347
130°	21	43	64	86	107	129	150	172	193	215	236	258	280	301	322	344	366	387	409	430
140°	27	55	82	110	137	165	193	220	248	275	303	330	358	385	413	440	468	495	523	550

Table Prepared by Hi-Tek Company, Inc.

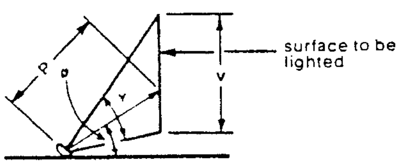


FIGURE 14-19.

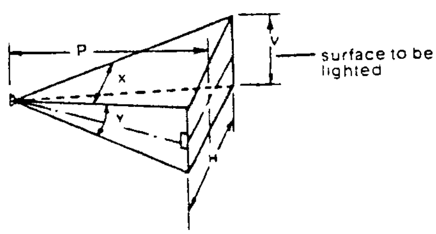


FIGURE 14-20.

Techniques for Measuring Vertical and Horizontal Beam Dimensions

Note: The vertical beam dimension "V" will be larger than that given, varying as a function of the angle Ø.

Note: If a luminaire with a horizontal beam (X) of 130° and a vertical beam (Y) of 100° is aimed directly at a verticle surface 50 feet away, the horizontal dimension of the beam in feet would be 215 feet and the vertical dimension would be 119 feet (see Beam Projection Chart).

than the spacing between fixtures rectangular beam fixtures are indicated. (Figure 14-21).

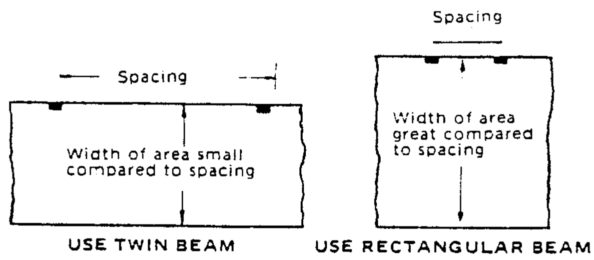


FIGURE 14-21.

Light Spacing Criteria
(Figures 14-19, 14-20 and 14-21 Courtesy Hi-Tek Co., Inc.)

14.5.4 Mounting Height and Spacing Recommendations

The recommended minimum mounting heights for most lighting applications can be found in Table 14-8 (Recommended Floodlight Mounting Heights). This table can also be used as a guide for general lighting applications when lighting an area from the perimeter.

TABLE 14-8

RECOMMENDED FLOODLIGHT MOUNTING HEIGHTS

POLE SETBACK (FEET)	WIDTH OF AREA IN FEET														
	20	40	60	80	100	120	140	160	180	200	220	240	260	280	300
10	20	20	20	25	25	30	35	40	45	45	50	55	60	60	65
20	20	20	25	30	35	35	40	45	50	50	55	60	65	70	70
30	25	25	30	35	40	45	45	50	55	60	60	65	70	75	80
40	30	35	40	40	45	50	55	55	60	65	70	70	75	80	85
50	35	40	45	45	50	55	60	60	65	70	75	75	80	85	90
60	40	45	50	55	55	60	65	70	70	75	80	85	85	90	95
70	45	50	55	60	60	65	70	75	80	80	85	90	95	95	100
80	50	55	60	65	70	70	75	80	85	85	90	95	100	100	105
90	60	60	65	70	75	75	80	85	90	95	95	100	105	110	110
100	65	70	70	75	80	80	85	90	95	100	105	105	110	115	120
110	70	75	80	80	85	90	95	95	100	105	110	110	115	120	125
120	75	80	85	85	90	95	100	100	105	110	115	120	120	125	130
130	80	85	90	95	95	100	105	110	110	115	120	125	130	130	135
140	85	90	95	100	105	105	110	115	120	120	125	130	135	135	140
150	90	95	100	110	110	110	115	120	125	130	130	135	140	145	145
160	100	100	105	110	115	120	120	125	130	135	140	140	145	150	150
170	105	110	110	115	120	125	130	130	135	140	145	145	150	155	160
180	110	115	120	120	125	130	135	135	140	145	150	155	155	160	165
190	115	120	125	130	130	135	140	145	145	150	155	160	165	165	170
200	120	125	130	135	140	140	145	150	155	155	160	165	170	170	175

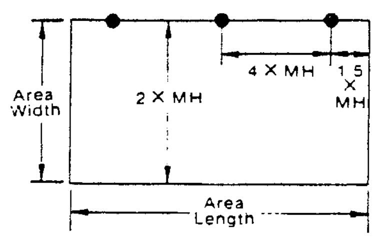
Recommended minimum mounting height in feet

Table prepared by Hi-Tek Company, Inc.

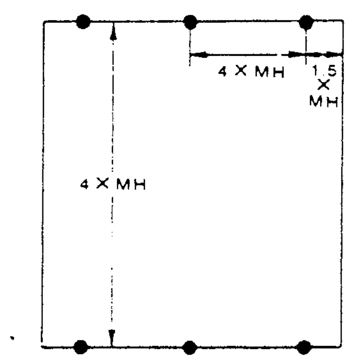
To use Table 14-8 locate pole setback distance at left, go across table to appropriate column for width of area (at top). The minimum mounting heights are where the two columns cross. (Example: Setback = 50 ft., width of area = 100 ft., read minimum height of 50 ft). The values are Illuminating Engineering Society (IES) recommendations rounded off to the nearest 5 feet for convenience sake. Note when lighting an area from only one side, the mounting height should be double that shown in Table 14-8.

There are four floodlight spacing techniques which may be used depending upon the facility's size and light placement. These four configurations are satisfactory by themselves, however, integration of one or more illustrations is recommended for good security lighting.

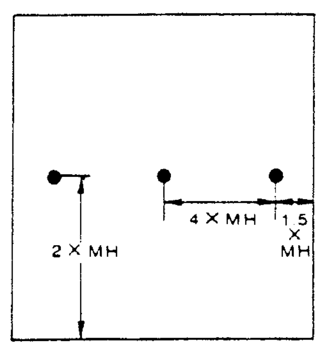
LIGHTING AN AREA FROM ONE SIDE



LIGHTING AN AREA FROM BOTH SIDES



LIGHTING AN AREA FROM THE CENTER



LIGHTING AN AREA FROM WITHIN

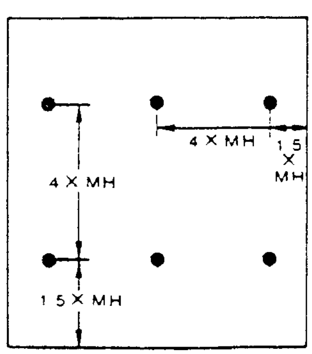


FIGURE 14-22. Floodlight Spacing Techniques

Note: For economy lighting projects, such as minimum security lighting, spacing ratios could be increased as follows:

4 x MH - increase to 5 x MH
1.5 x MH - increase to 2 x MH
2 x MH - increase to 2.5 x MH

(Illustrations Courtesy Hi-Tek Co., Inc.)

14.5.5 Pole Selection

In selecting the proper pole for the lighting system investigations must be made to assure that the entire structure is suitable for the wind loads imposed by a specific location. The poles listed in this section are designed to withstand dead loads and theoretical dynamic loads developed by variable wind velocities with 1.3 gust factor. Poles that are to be located in areas of known abnormal conditions will require special consideration. In general, coastal areas require that the following wind velocities be used for applications within 30 miles of the coast.

GULF COASTAL STATES

Louisiana, Mississippi, Alabama . . . . . 100 mph

Texas .90 mph

ATLANTIC COASTAL STATES

Florida, South Carolina, North Carolina . 100 mph

Conn., Maine, Mass., New York . . . . . . .90 mph

Rhode Island, Virginia . . . . .90 mph

PACIFIC COASTAL STATES

Oregon, Washington . . . . .90 mph

GREAT LAKES STATES . . . . .90 mph

ALASKA and HAWAII . . . . .90 mph

The wind speeds were taken from the 1975 "Standard Specifications for Structural Supports for Highway Signs, Luminaires and Traffic Signals" by American Association of State Highway Transportation Officials (AASHTO). The wind speeds are based on a 25 year mean recurrance interval at an elevation of 30 feet above the ground, as is recommended by ASSHTO for light standards 50 feet or less in height. The individual designer/engineer should consider other factors such as isolated high wind areas in choosing the specified wind speed.

There are five basic steps in the selection of lighting poles:

1. Determine basic wind velocities to be used for given location.
2. Select bracket to be used. Determine that each tenon will carry individual fixture size and weight.
3. Determine the total projected area of equipment to be installed on pole. (Consists of luminaires and brackets.)
4. Determine the total weight if required by adding total luminaire weight to bracket weight.
5. Select the lightest duty pole with the proper tenon and loading capabilities to carry load determined in step 2 and 3 for expected wind velocity.

As an example, if an engineer wanted to determine the correct round steel pole and bracket to mount three Hi-Tek Corporation Model TF1000 M RA units in a row in Savannah, GA, the following steps would be taken:

1. Savannah, Georgia falls in the 90 mph category.

2. Select Hi-Tek bracket number S3-B3-4P because TF1000 has a projected area of 4.2 $ft.^2$ (Number S3-B3-2P cannot be used.)

3.

Projected area per luminaire		4.2 $ft.^2$
Total number of luminaires		x 3
	Total	12.6 $ft.^2$
Projected area of selected bracket S3-B3-4P		+ 1.9 $ft.^2$
	Total	14.5 $ft.^2$

4.

Weight per luminaire		76 lbs.
Total number of		x 3
	Total	228 lbs.
Bracket weight		+ 37 lbs.
	Total	265 lbs.

5. Hi-Tek pole number St-30-4H-AP would prove to be a suitable unit.

Ultimate selection would then be based on the three following poles*:

- <u>Aluminum Post - Top Poles</u>

Cylindrical shaft poles under this category are fabricated from 6061-T6 aluminum alloy. Tapered shaft poles are fabricated from 6063-T6 aluminum alloy. Anchor base models include base

---

*Models of Poles taken from Hi-Tek Corporation Catalog, "Industrial Lighting." This should not, however, be construed as an endorsement of any manufacturer's pole. Hi-Tek is used in this study since their sales selection literature provided necessary report input.

covers. Embedded models are bituminous coated inside and out for a length of 2-3 feet from the base end. All units are rated 100 mph constant wind (1.3 gust factor).

- Aluminum Floodlight Poles

Shafts for these poles are fabricated from #5086-H34 marine sheet alloy. Bases are cast from 356-T6 aluminum and include anchor bolt covers. Shafts over 40 feet are shipped in two sections. Anchor bolt size: 8'-14' poles, 1/2" x 12" x 3"; 10' - 16' poles, 3/4" x 15" x 2"; 20' - 35' poles, 1" x 36" x 4"; 35'-50' poles, 1 1/4" x 48" x 4".

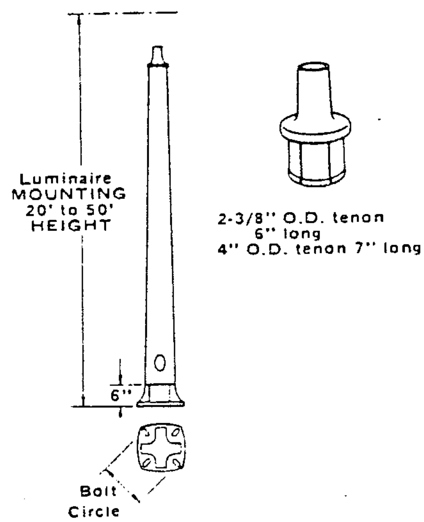


FIGURE 14-23. Aluminum Floolight Poles
(Illustration Courtesy Hi-Tek Co., Inc.)

- Steel Poles - Round Tapered

(10 to 45 feet Anchor, Embedded, or Transformer Base Prime Painted)

All of these poles have welded, tapered shafts of hot-rolled commercial quality carbon steel/anchor base is of structural quality hot-rolled steel/all poles are prime painted with an iron oxide rust inhibitive/nut covers provided on all poles/acorn nuts provided on pedestal poles. Shafts over 40 feet are shipped in two sections.

Cost

The costing for lighting poles is dependent on the geographical location and system used. Mostly all contractors will include the pole cost together with the lighting system cost. Prices range from $200 per pole and can cost as much as $3,000 depending on mast size.

14.5.6 Outdoor Lighting Estimating Guide

The Area Coverage Tables (Tables 14-9 and 14-10, Courtesy of Hi-Tek/Lithonia Corp.) present a way of estimating the number of fixtures needed to light an area to one initial footcandle. The tables that follow list those fixtures most commonly used and are intended for approximation purposes and not to replace a precise lighting survey.

How to use the area coverage tables: Each table gives square feet per fixture coverage for three size classifications: Small, Medium and Large as in the Area Size Approximator Table on the folowing page.

AREA COVERAGE TABLES

Table 14-9

"TF" SERIES AREA COVERAGE (SQ. FT./FIX.) (1 Footcandle Initial)

	Catalog Number	Lge.	Med.	Sm.
	TF 250S RA	11 000	8 250	5 500
30 000 Lumen Lamp →	TF 250S RA	12 000	9 000	6 000
	TF 400S RA	20 000	15 000	10 000
	TF 1000S RA	56 000	42 000	28 000
40 000	TF 400M RA	13 600	10 200	6 800
Lumen Lamp →	TF 400M RA	16 000	12 000	8 000
110 000 →	TF1000M RA	44 000	33 000	22 000
Lumen Lamp	TF1500M RA	62 000	46 500	31 000
	TF 400H RA	9 200	6 900	4 600
	TF 1000H RA	25 200	18 900	12 600

Table 14-10

"TFL" SERIES AREA COVERAGE (SQ. FT./FIX.) (1 Footcandle Initial)

Catalog Number	Lge.	Med.	Sm.
TFL 70S TA	2320	1740	1160
100S TA	3800	2850	1900
150S TA	6400	4800	3200
200S TA	8800	6600	4400
TFL 175M TA	5600	4200	2800
250M TA	8200	6150	4100
TFL 175H TA	3440	2580	1720
250H TA	5200	3900	2600

AREA SIZE APPROXIMATOR	
WIDTH VS. MOUNTING HEIGHT	AREA SIZE
Width is less than 1½ x mounting height	Small
Width is 1½ x 2½ x mounting height	Medium
Width is over 2½ x mounting height	Large

Determine area size and obtain area coverage per fixture from "Area Coverage" Table for fixture type desired.

Find quantity of fixtures required by calculating the total area to be lighted in square feet (width x length) and dividing by the area coverage per fixture.

Follow these easy steps to determine the approximate number of fixtures required:

Example: Area Size: 60' Wide x 200' Long with a 30' mounting height (pole or building mount). Light the area to 1 Footcandle, Initial using #TF 400M TA fixture (400 watt metal halide).

1. AREA DETERMINED

Determine Area Type.

Width is between 1½-2½ x mounting height

$$\frac{\text{Width}}{\text{Mounting Height}} = \frac{60}{30} = 2 \text{ Medium area}$$

2. AREA COVERAGE

"Medium" area using #TF 400M fixture equals 10,190 sq. ft./fix. coverage

Consult "TF" Series Area Coverage Table.

"TF" SERIES AREA COVERAGE (SQ. FT./FIX.) (1 Footcandle, Initial)			
Catalog Number	Small	Medium	Large
TF 400S	10,000	15,000	20,000
TF 400M	6,790	10,190	13,600
TF 400H	4,600	6,900	9,200

3. FIXTURES REQUIRED

Determine Approximate Quantity of Fixtures by Dividing Total Area by Coverage Per Fixture.

$$\text{Fixtures} = \frac{60 \times 200}{10{,}190} = 1.2 \text{ Use 2 Fixtures}$$

4. SPACING CHECK

Check to Assure that Fixtures are not Spaced Greater than Five Times the Mounting Height in Either Direction.

OTHER FOOTCANDLE LEVELS

If an initial footcandle level other than 1 (one) is desired, use the following correction factors:

DESIRED FOOTCANDLES:	CORRECTION FACTOR
1	1.0
2	.5
3	.33
4	.25
5	.20

Example:
For 5 Footcandles, initial:

10,190 (sq. ft./fix.) x .20 = 2038 sq. ft./fix.

$$\text{New Fixture Quantity: } \frac{60 \times 200}{2038} = 5.89 \text{ Use 6 Fixtures}$$

MAINTENANCE FACTORS

If maintained footcandle level is desired, multiply the area coverage per fixture by the maintenance factor.

Maintenance factor is determined by multiplying the lamp lumen depreciation factor (LLD) by the luminaire dirt depreciation factor (LDD). The lamp lumen depreciation factor is usually the mean lumen value of the lamp (see Lamp Performance Characteristics Table in the General Lighting Design Section of this catalog). The luminaire dirt depreciation factor range is described in Section 9 of the Illuminating Engineering Society Handbook. A .9 dirt factor is commonly used.

Example:
For 5 Footcandles, maintained:

2038 (sq. ft./fix.) x .9 (LDD) x .75 (LLD) = 1375.65 sq. ft./fix.

$$\text{New Fixture Quantity: } \frac{60 \times 200}{1375.65} = 8.72 \text{ Use 9 Fixtures}$$

FIGURE 14-24. Criteria for Determining Quantity of Fixtures Needed (Courtesy Hi-Tek Company, Inc.)

Hi-Tek/Lithonia Corporation currently markets the "TF", "TM", and "TFL" series of outdoor industrial lighting fixture. Selected models are as follows:

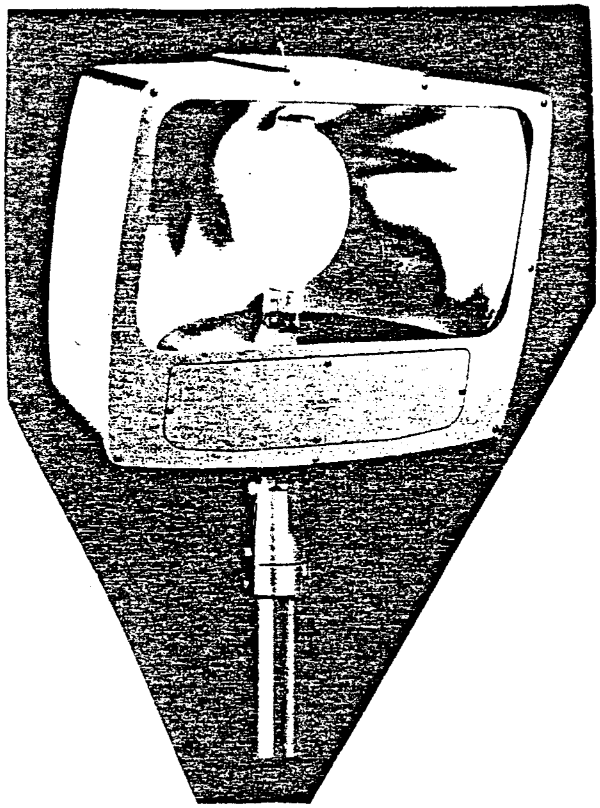


FIGURE 14-25. TF Series

1000-watt Omni-Flood with Optional Integral Slipfitter

Optics--Sealed to inhibit entrance of outside contaminant. Relector is one-piece, anodized aluminum.

Housing--National Electrical Manufacturers Association (NEMA) heavy-duty

Light Pattern--Rectangular or twin beam.

Ballast--Constant-wattage autotransformer.

Installation--Removable power module provides easy up-grading to more efficient light sources as well as simplified maintenance and reduced cost.

Construction--Housing is strong, lightweight die-cast aluminum. Yoke is hot-dipped galvanized steel. Lens is thermal and shock-resistant tempered glass. Luminaire is enclosed and gasketed. All hardward is series 400 stainless steel.

Listing--U.L. listed suitable for wet locations.

Photocontrol--NEMA type twist-lock (option).

Finish--Standard is American Standards Association (ASA) 70 gray baked enamel.

The "TFL" and "TM" series are very similar in appearance to the "TF" 1000-watt Omni-Flood light, hence, the photographs are excluded.

"TFL" Series - Omni-Flood, Four-Wattage

Features:

Optics--Sealed to inhibit entrance of outside contaminents. Reflector is one-piece, anodized aluminum.

Housing--NEMA heavy-duty, compact (just 15 3/8" wide by 18 5/16" high).

Light Pattern--Twin beam applications with two-position adjustable socket.

Ballast--Mercury Vapor: Constant-wattage auto-transformer. Metal-Halide: Peak-Leak auto-transformer. High-Pressure Sodium: High leakage reactor.

Installation--Hinged bezel for easy access to lamp and electrical components.

Construction--Housing is strong, lightweight, die-cast aluminum. Yoke is hot-dipped galvanized steel. Lens is thermal and shock-resistant tempered glass. Luminaire is encloed and gasketed. All hardware is Series 400 stainless steel.

Listing--U.L. listed suitable for wet locations.

Photocontrol--NEMA type twist-lock (option).

Finish--Standard is ASA 70 gray baked enamel.

"TM" Series - Marine Flood U.L. 595

Features:

Optics--Choice of two Optical Systems. Rectangular beam spread with maximum candlepower at nadir and Twin beam spread with two max-candlepowers for wider spread. Both beam spreads use a one-piece, anodized aluminum reflector with adjustable socket.

Housing--NEMA heavy-duty.

Ballast--Constant Wattage Peak-Lead for Metal-Halide and Auto-Regulator for High-Pressure Sodium. All high power factor.

Installation/Maintenance--Easily removable power module with polarized positive locking plug to the lamp socket, provides fast access to all electical components without opening the optical chamber. Fixture is prewired with 2 ft. of 16-3 SO Cable.

Construction--Housing is strong, lightweight, copper-free, die-cast aluminum. Yoke is hot-dipped, galvanized steel. Lens is thermal, shock-resistant, tempered glass. Luminaire is enclosed and gasketed. All hardware is Series 400 stainless steel.

Cost for Hi-Tek "TF", "TFL", and "TM" Series:

The costing for the models stated are estimated at \$275.00 to \$400.00 less pole and installation. Installation costs vary depending on geographical location and union/non-union contracting. Installation costs range from \$18.00/hour to $25.00/hour.

General Electric Corporation also markets outdoor luminaires; selected models are as follows:

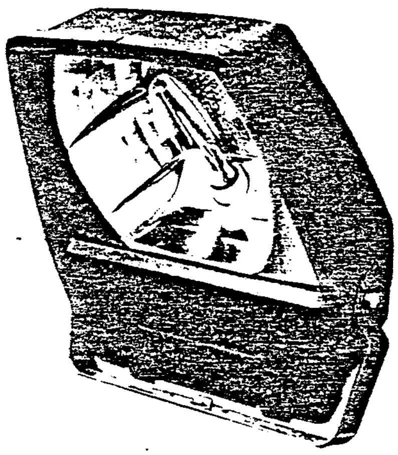


FIGURE 14-26 (a)

G.E. VLU Powerflood Luminaire
(Illustrations Courtesy of
General Electric Corp.)

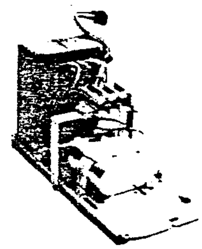


FIGURE 14-26 (b)

Ballast Tray

Removable Ballast Tray: Permits stocking flexibility and easy conversion from one High Intensity Discharge light source to another (Figure 14-26 (b)).

Easy Maintenance: Access to the luminaire for relamping or cleaning is readily accomplished by loosening two captive screws and swinging open the front door in its hinges. This allows the maintenance man to use both hands for his work. If total maintenance is ever required, the front door is completely removable.

High Maintained Efficiency: Weatherproof construction protects the optical and electrical systems from outside elements. The sealed and activated charcoal filtered luminaire protects the ALGLAS®-finished, hydroformed reflector providing maximum light levels for longer time periods. The filter is designed to effectively remove particulate matter and gaseous contaminants resulting in fewer manhours spent for maintenance.

Versatile Mounting: There is a choice of either a heavy-gauge galvanized steel trunnion or a cast aluminum, knuckle-type slipfitter; both have a vertical degree scale. The trunnion version is particularly suited for mounting on flat surfaces such as wood crossarms, concrete pads, building parapets, etc. The knuckle-type slipfitter is designed for pole tops; its internal wiring and clean, modern design provides excellent day-time appearance.

Easy Installation: The lightweight, rugged, heavy-duty fiberglass reinforced polyester construction permits easy hand-ling and fast installation. The built-in rifle sight allows daytime aiming. The trunnion mounted version has a readily accessible prewired terminal board and a grommeted strain relief bushing. The knuckle-type slipfitter has an integral wiring com-partment with pre-stripped extra length leads.

Choice of Light Sources: Economical and modern Lucalox®, mercury, or metal halide light sources of various wattages and voltages are controlled with quality ballasts.

Automatic Dusk-to-Dawn Control: An optional, built-in photoelectric receptacle is available for individual luminaires.

Suggested Mounting Height: 25 feet.

Cost: Estimated cost range for High Pressure Sodium fixture is $400.00 - $450.00 (less pole and installation).

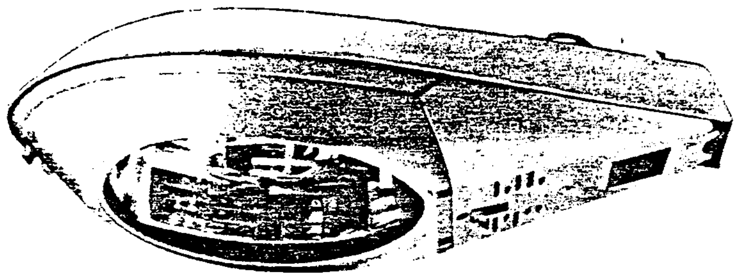


FIGURE 14-27. G.E. M-400A Luminaire

This model offers a shielded optical system (incorporating a faceted, hydroformed reflector and a clear flat glass lens) providing 90° cutoff. The unit would be used within a facility along road ways or paths where the 90% cutoff would drastically reduce glare in the drivers line of vision caused by the strong illumination from power-floods. This model is available with 200, 250, 310 and 400-watt Lucalox® and 400-watt mercury or metal halide light sources. Some key features are:

Easy Relamping and Optical Assembly Servicing: one latch opens captive door for access to the entirely sealed reflector system.

Minimal Light Loss from Contaminants: charcoal-filtered and gasketed optical assembly greatly reduces light loss which results from gaseous and particulate materials. . .and is factory-installed for high-quality sealing.

Simplified Assembly on the Ground or in the Air: two-bolt slipfitter allows line crews to install the luminaire on its bracket on the ground, or to mount bracket and luminaire on the pole in the air with minimum effort and time.

Internal Photoelectric Control Protected from Damage: Astrodome control (optional), located inside the housing, is protected from outside dangers such as rocks, tree limbs and/or common maintenance problems.

Optimum Lighting Efficiency: The patented ALGLAS® treated reflector is precision formed for optimum lighting effiency. The Alglas silicate film is chemically bonded to the aluminum interior and exterior to seal the surface. Alglas® is lightweight, non-breakable, and glass smooth.

Suggested Mounting Height: 30 feet.

Cost: $200.00 (less pole and installation).

Floodlight options such as light sensing timers (automatic dusk-to-dawn controls) and QRS (Quartz Restrike Systems) are factory installed. Photoelectric cells and receptacles must be purchased per unit. Estimated cost of the cell is $18.00 and the receptable is $18.00 per unit. Another method of dusk-to-dawn control is the time clock. It can handle five to seven luminaires, is pre-set and has been proven to be more energy and cost efficient.

14.6 Guards, Watchmen, and Watchdogs

Security of plant facilities, equipment, fuels and storage of raw and finished materials are either under plant employees' custody, a plant-employed guard force or a contractual guard service.

An essential feature of plant protection during non-operating hours is adequate guard patrols. Plant management should carefully select the proper guard personnel and equipment, Also the layout and schedule of routes to be patrolled. If a contract guard service is employed, most of the administrative details may be developed under the contract, but this should not relieve management's responsibility to insure that the contract service meets standards equal to a company-operated service.

The initial and continuing training of a plant guard staff should be a formal, well-documented program covering all applicable protection procedures. They should be acquainted with the general nature of the facility's operations and have a specific knowledge of inherent or special hazards of stored products. They should be familiar with all of the fire protection equipment, both manual and automatic, know the location and operation of fire alarms, and the proper method of informing the fire department or designated company officers of the location and directions to the fire or spill area within the plant.

Finally, the guard should maintain a shift log and prepare reports of all observations and actions made during a shift including any infraction of plant regulations. The observations can be made by roving patrols moving on a regular or staggered frequency. The provision of clock punch systems insures that the frequency and predesignated extent of patrols are maintained. If a guard observes hazardous waste materials--paint and oil--soaked rags or sweepings left in open area, or drums containing oils are improperly stored, even temporarily, they should be instructed to report unsafe conditions to management. They should also have a degree of responsibility to enforce no smoking regulations in designated areas. They should in fact be fully cognizant of the content of the plant's spill prevention control and countermeasure plan (SPCC Plan). The Environmental Protection Agency regulations on oil pollution prevention (40 CFR 112) requires that owners and operators of certain onshore and offshore oil storage and handling facilities prepare a certified Spill Prevention Control and Countermeasure Plan (SPCC Plan). It is anticipated that implementation of properly prepared plans will significantly reduce the number of spill events which occur each year. The effect of implementation should be manifested through a reduction in the amount of oil reaching the navigable waters and adjoining shorelines of the United States and a lessening of the associated environmental consequences. A copy of the Regulation is included as Appendix A. Any unusual condition which is found and cannot be corrected by the guard himself, should be reported immediately to the alarm center or central station so that the situation can be remedied without undue delay.

Most security organizations are comprised of retired and former law enforcement officers and individual security specialists. Most offer security consulting, surveillance, uniformed armed and unarmed guards, radio mobile patrols (including four-wheel drive jeeps), K-9 patrols and strike forces (in the event of an unusual occurrence, armed and unarmed personnel are ready to implement protection of facility).

<u>Cost</u>:

Table 14-11 lists descriptions and costs for a typical security service. These prices reflect an average cost throughout industry.

The service also offers the following checklist of no-cost benefits.

- Overtime: Client pays the same rate for 168 hours a week as you would pay for 40 hours a week. No matter how many guards are needed, the price will be the same.
- Sick: If a guard gets sick, he is replaced at no cost.
- Insurance: One million dollars liability.
- Training: All guards are trained before hiring.
- Outside Costs: Client does not have to pay F.I.C.A., hospitalization, etc.

TABLE 14-11

SECURITY COST TABLE

QUANTITY	DESCRIPTION	UNIT PRICE
1 Hour	Uniformed Security Guard (Unarmed)	$7.25
1 Hour	Radio-Motorola Model MT-500	.25
1 Hour	Smith & Wesson Service Revolver, Model 10	.25
1 Hour	Patrol Vehicle	2.50
1 Hour	K-9	1.50
	24-Hour Dispatcher Service	N/C
	On-Site Supervisory Checks	N/C
	Daily Log Reports	N/C
	Incident Reports	N/C
	Supervisor's Evaluation for Security Procedures and Job Description Done On Site Prior to Assuming Contract	N/C

Rates Based on 40 Hours Minimum

- Administrative Costs: None
- Secondary Costs: No sick or annual leave to pay.
- Internal Relationships: Guards can be rotated so that they don't develop too close a personal relationship with facilities employees.
- Unions: Non-union
- Disciplinary Problems: Occasionally situations arise where a guard presents a problem; he can be replaced without inquiry.

- Supervision: Round-the-clock supervision checks on the guard force and if for some reason a guard is late, the supervisor fills in at no extra cost.
- Uniforms: Cost for each is $200.00; paid by the security service company.
- Options: Client has the option to cancel out within 15 days after the first month.

Note: The information provided in this section was supplied by Sting Security, Inc., Marlow Heights, MD.

14.6.1 Watchdogs

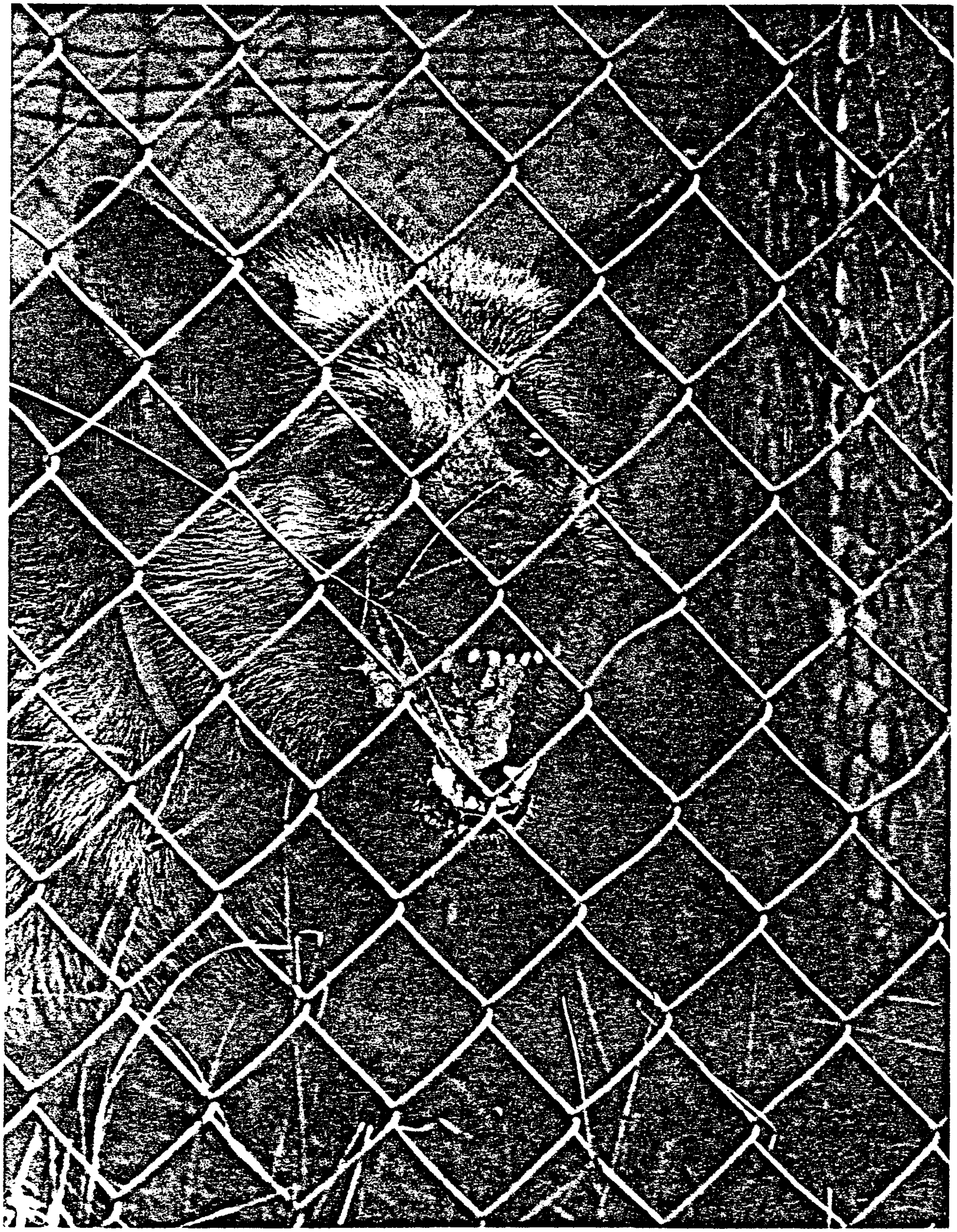


FIGURE 14-28. High Security Watchdog
(Photograph Courtesy K-9 Security Co., Ltd.

There is no intent to indicate that bulk oil storage plants require K-9 dog protection. The following information is provided to indicate the degree of security that can be attained.

There are two varieties of watchdogs: Command dogs and guard dogs. Doberman Pinscher and German Shepherd (Alsation) dogs are most commonly used. Command dogs properly trained act only on command from their trainer. They are playful, totally tame animals that have been trained to attack and will do so upon word from the trainer. Since command dogs need their trainer present, plant management must decide whether it would be cost beneficial to pay for the more expensive command dog/trainer combination.

Guard dogs are also trained to protect and/or attack with no trainer present. Trying to train a dog to be a guard dog would be a waste of time and effort, since guard dogs are bred for their specific purpose. The guard dog must also be further trained "on site" at a specific plant. Some dogs when brought to a large facility will not be as effective unless they are familiar with the area they are guarding.

Figure 14-28 illustrates the animal's reaction to a would-be intruder. The individual trying to gain entrance to a facility would become suddenly cynophobic upon seeing this vicious animal's intent. Trying to "sweet-talk" the animal would prove worthless. All the properly trained animal knows is that no one is to get in.

At one time, it was common practice for K-9 companies to deliver dogs to the facility before dusk or closing and then retrieve them in the morning or when business resumed. The K-9 companies would keep the dogs in a centrally located kennel where feeding and care would take place. This practice has been improved upon and it is now more common to have the animal live on the premises in a fenced cage (Figure 14-29). When the plant guard has secured the facility and upon leaving the main gate, he will pull the gate cord, opening the cage freeing the dog (Figure 14-30). Just before business resumes a trainer will arrive at the facility, feed, water, and secure the dog.

With the use of electronic sensing devices becoming prevelent guard dogs cannot be used in areas where such devices are implemented and vice-versa, due to the the obvious number of false alarms which would occur. Decisions on whether to use guard dogs verses electronic detection systems depends on the quality of security needed and both have their advantages and disadvantages.

At some high security locations dogs are free to patrol on a regular basis within the confines of a fence within a fence and electronic sensors can then be used within the plant property actually within the confines of the double fence.

Security dogs are available from K-9 companies for lease or direct sale. Prices are in the range of $600 per six-month lease and $675 per one-year lease. Direct purchase of a dog ranges from $500 to $5,000 depending upon the breed and quality desired. (Florida and West Coast prices are 20% less.) Once purchased, the facility would assume full responsibility and

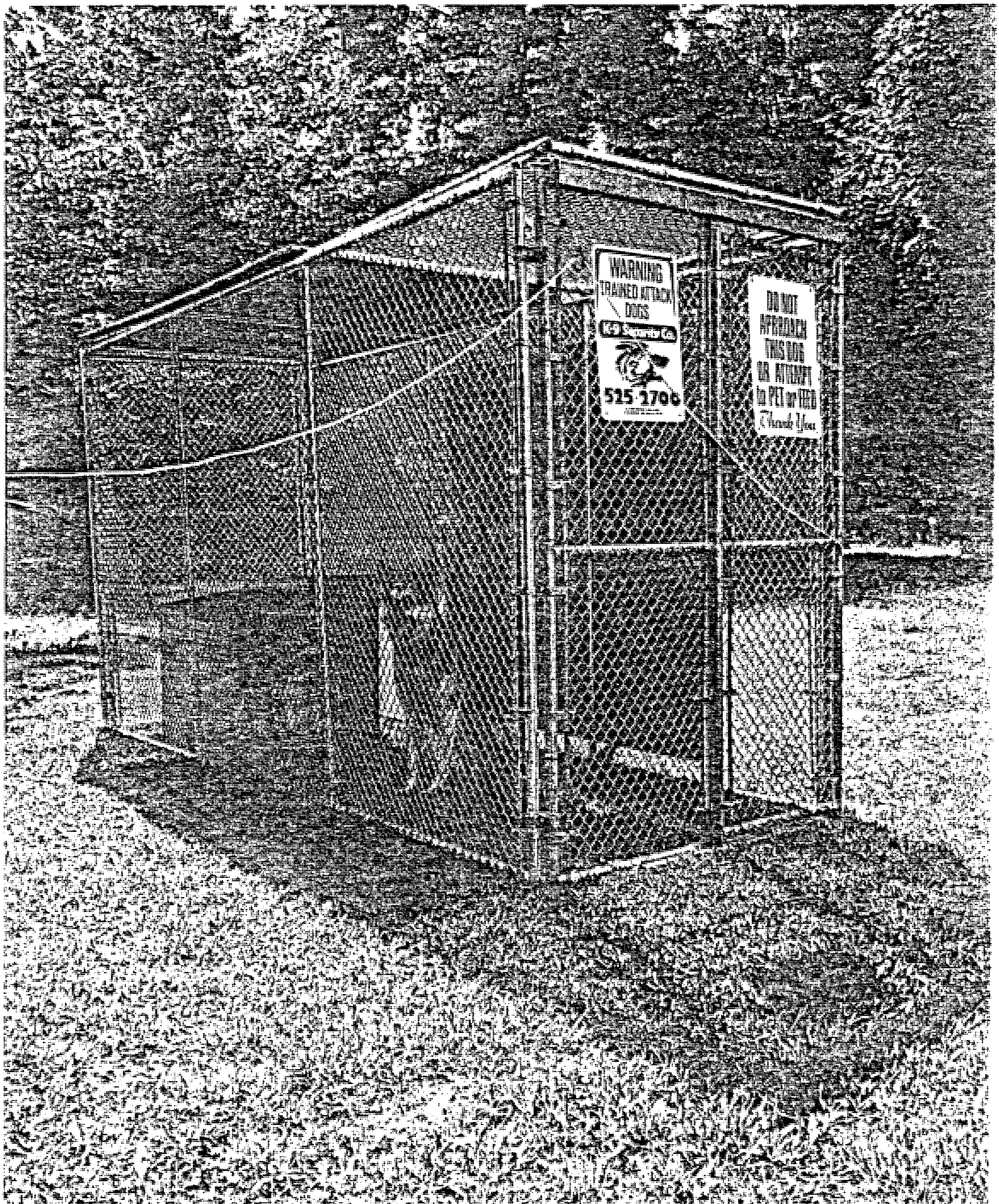


FIGURE 14-29. Off-Duty K-9 Retention Cage

Note the pull cord gate opening device. Dog has shaded area and dog house during plant's operating hours. (K-9 Security Photograph)

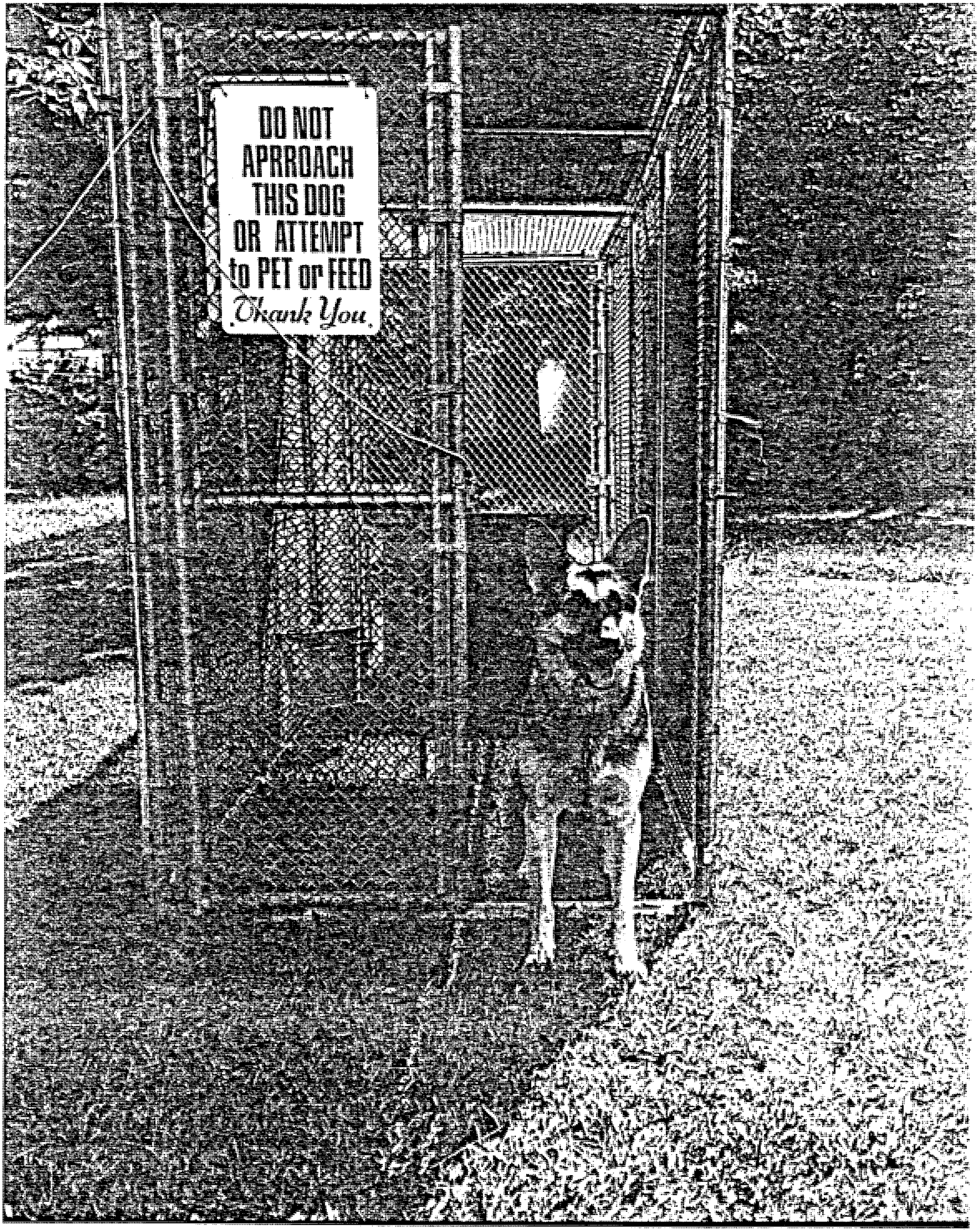


Figure 14-30. Off-Duty K-9 Retention Cage

Dog is free to roam facility
(K-9 Security Photograph)

would need their own staff trainer. In this case, there would be no exchange or trade-in for another animal. Leasing a dog allows for the consideration that if for some reason the dog does not prove effective, it can be replaced with another dog.

14.7 Pier, Waterfront, and Shoreline Security

The weak security link in most waterfront facilities: refineries, marketing terminals, and marine loading/unloading and storage plants is the open shoreline. Illegal entry can be easily gained through this unsecured boundary by almost any person, i.e., children, saboteurs, thieves, and in some cases, disgruntled employees intent on mischief and/or troublemaking.

During a period of civil disturbance in the 1960's some plants proceeded to correct this situation by fencing the land area above the foreshore or high water mark. The metal fences in some cases extend up and onto the pier providing access to the loading/unloading dock, with a locked gate controlling entry into the plant proper. The sides of the fence paralleling the sides of the pier should restrict side entry around the gated section of the fence. The gate is kept in the closed and locked position whenever the dock is not in service.

As far as practical, equipment on the loading dock should be fully secured. Pump controls should be locked and fuses removed to prevent unauthorized activation of the pumping system.

The terminal flanges of the docklines should be gasketed and blank flanged and full bolted in position, intermitent bolt spacing should not be considered as acceptable securement.

Portable drip catch trays or pans should be either removed from the dock area (where they should not really be needed when the dock is idle) or emptied and cleared ready for future use.

Liferings and lifelines and fire extinguishers present a theft problem since they should be maintained ready for use at any time. They can, however, be stored in marked containers where they are protected from the weather and do not present a visible inducement to theft.

Should plant patrols be used the shoreline should be subjected to frequent patrol service.

14.8 Alarm Detection Systems

Outdoor facilities are especially vulnerable to theft, vandalism, malicious mischief, and sabotage since eye-witnessing (casing the site) by the intruder is accomplished rather easily. ITS Systems, Pittsburg, PA., installed one alarm detection system that reduced a lumberyard's losses by $10,000 annually. (Much of the theft was occuring during nighttime hours.) In this case, a buried seismic sensor was used. There are also microwave, photoelectric detection, infrared and fence vibrator systems now in use throughout industry. Descriptions of the systems follow.

14.8.1 Seismic Sensors

Where security systems are exposed to blizzards, blowing debris, wild animals and wind, buried seismic systems are used. Buried seismic systems are programmed to detect footsteps and screen out other noises and vibrations. Dynamic microphones or sensors placed about 12 feet apart have a range of approximately 20 feet and are linked by a cable that carries impulses genereated by vibrations to a processor. When the signals reach the processor at a guard or central station, they are amplified and equalized to eliminate unrelated intruder motion frequencies. After the amplification process, signals are converted to pulses compared to a standard single threshold. Each pulse crossing the threshold is judged according to count and periodicity. If the pulses meet the set criteria for human footsteps, an alarm is triggered. A guard or monitor can then listen to the footsteps to determine how many intruders are present.

Figure 14-31 illustrates a metal fence vibrator unit which can be used in conjunction with a buried seismic sensor. Vibrator units installed on every other fence post once activated vibrate the fence upon physical contact. It can be actuated without physical contact, however, in this instance at the Bonneville Power Administration Keeler Substation, Oregon. At certain times each morning, this metal fence intruder detection system would vibrate the fence. Investigation revealed the source to be a train passing about the same time every morning, hence setting off the alarm. Discriminator sensors might be a solution in cases such as this.

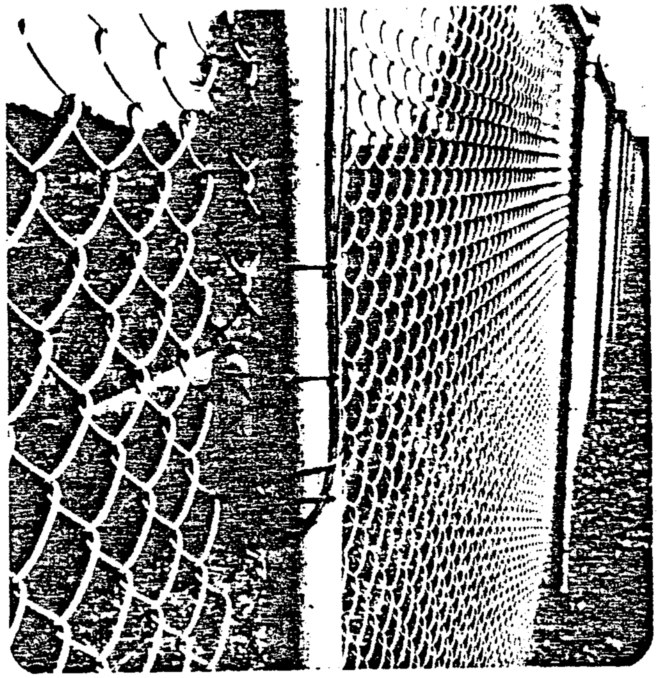


FIGURE 14-31. Metal Fence Intruder Detection System

There exists two different philosophies in designing a system involving whether or not an intruder should know he has tripped an alarm. Using the seismic sensor, an intruder can be detected without his being aware that he has tripped an alarm. It also restricts his being able to tamper with the system. The underground sensors are not subject to varying weather conditions and can be installed in uneven terrain, around corners, or across landscaping.

The system can also be buried under concrete or asphalt (Figure 14-32). It can be placed before paving or narrow slits can be cut through the concrete and sensors and cable dropped

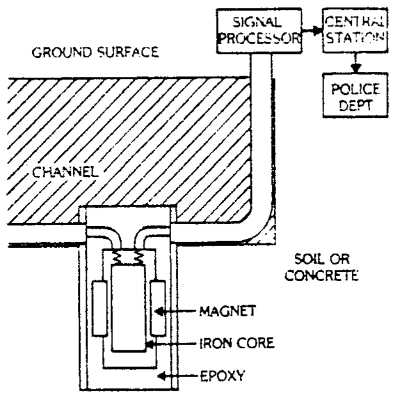


FIGURE 14-32. Buried Seismic Sensor System
(From Security Distributing & Marketing Magazine 6/80)

in a trench about 18 inches deep. Some portable systems with special sensor cases are equippeed with spikes so it can be driven into the ground and then moved later. Discriminator sensors are used near the source of normal vibrations (i.e., traffic or machinery) in order to filter out noise.

14. 8 .2 Microwave Detection

Outdoor microwave links are out-of-sight systems that provide volumetric protection along a plant's perimeter. A beam of microwave energy is radiated between a transmitter and receiver so that a person entering the beam pattern causes a decrease in signal being detected by the receiver thus triggering an alarm. Unlike indoor microwave detectors that operate on the Doppler principle, outdoor systems detect not only an intruder's motion, but also his presence within the beam. Also outdoor microwave units are bistatic with transmitter and receiver in separate housings separated by a given distance. (Indoor systems are monostatic--the transmitter and receiver in one unit.)

Beam diameters vary from 2 ft. to 40 ft. and can operate for lengths of up to 1,500 feet. Microwave systems are designed to operate in snow, rain, or fog and allow for flying objects such as birds, paper, or leaves. The alarm, however, can be triggered by small animals entering the coverage area. It is recommended, therefore, that the units be set inside a fence at least five feet from the perimeter so that the intruder cannot vault both the fence and the beam. The ground should be flat, free of trees, brush, weeds, or other obstructions that may restrict the coverage area. The "offset technique"--zones which overlap each other so that triangular areas between transmitters and the ground are covered by transmitters in another zone--is used in high security applications (Figure 14-33).

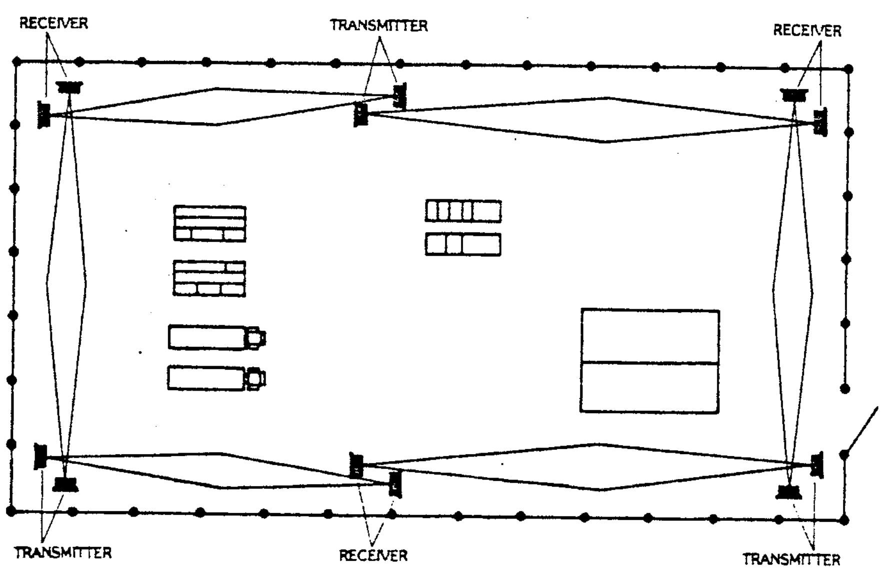


FIGURE 14-33. Recommended Microwave System Layout
(From Security Distributing and Marketing Magazine,6/80)

In general outdoor microwave detection systems are not affected by strong vibrations or radio frequency interference and can serve as a high security system when integrated with other security measures.

Figures 14-34 and 14-35 are photographs of microwave detection systems currently being tested along with other types of systems within an electrical substation Bonneville Power Administration, Oregon. It is possible for an intruder to gain undetected entrance by crawling under the units. Configurations as in Figure 14-33 tend to control this deficiency. The added interior perimeter protection with proper placement of multiple transmitter and receivers should be observed.

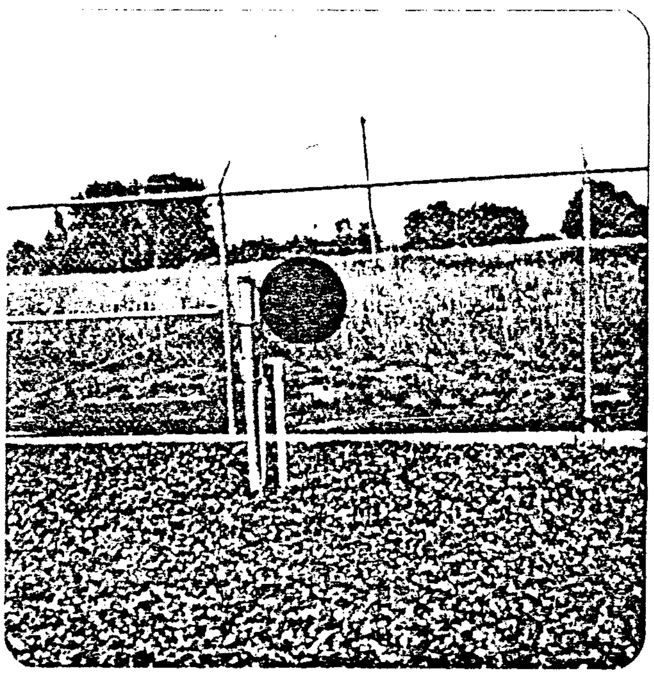


FIGURE 14-34

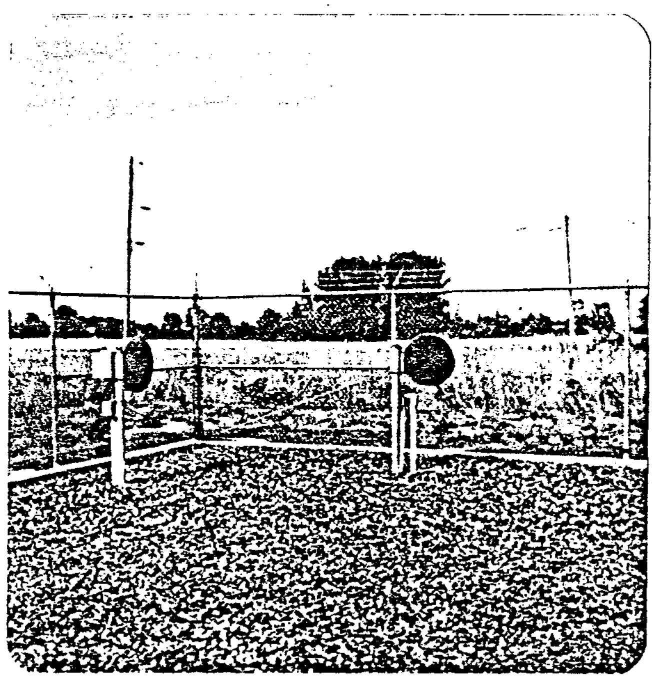


FIGURE 14-35

Microwave Sending and Receiving Units

Most outdoor microwave units have a cost effective 1,500 foot coverage range. On a cost per foot coverage basis, it is about $1 a foot.

14.8.3 Photoelectric Detection

Outdoor photoelectric systems create an invisible fence made up of one or more infrared beams. A transmitter emits a pulse modulated beam from a (LED) light source aimed at a receiver up to 500 feet away. When the conical beam is broken, an alarm activates.

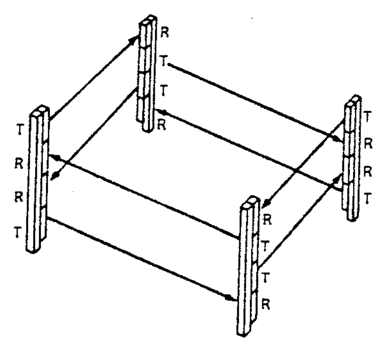


FIGURE 14-36.

Photoelectric Detection System

Figure 14-36 illustrates the perimeter configuration of transmitters (T) and receivers (R). Note how the arrows are criss-crossed to allow steady flow of signal patterns.

Extreme weather conditions such as fog, smog, dust storms, and snow can cause gradual loss of signal and an unnecessary alarm. Systems can be designed to compensate for this that disqualify any gradual loss of signal caused by adverse weather conditions. Also, flying debris, leaves, paper or birds can be eliminated as a source of alarms by a circuit that permits the beam to be broken for a certain length of time before an alarm is triggered. The photoelectric detection system should be installed on level terrain at least two feet away from a perimeter fence (Figure 14-37).

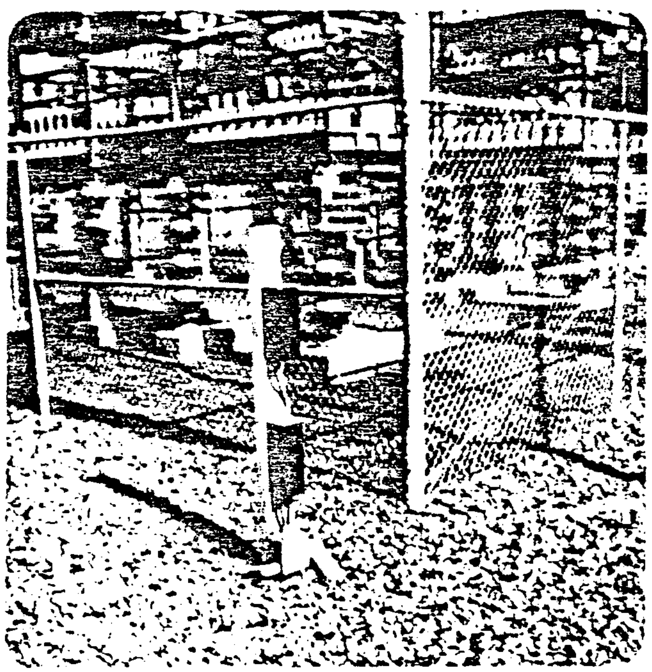


FIGURE 14-37. Infrared Intruder Detection System, Bonneville Power Administration, Oregon

Equipment should not be positioned directly into the rising or setting sun. Surrounding buildings, hills, or the horizon in most cases can be used to adequately block the sun's direct rays. Infrared systems need much closer spacing than microwave systems for proper and complete operation.

14.8.4 Local Alarms

The term "local alarm" includes any noise and/or light producing device used to protect a selected area. It may be a siren, horn, or bell sometimes combined with a flashing light. These devices should be mounted high on an outside wall or structure with full protection against weather and tampering. The connecting cable should also be tamper resistant. Most bells have internal battery power supplies that permit the unit to operate if line power is interrupted and even if the unit itself is pulled free from the wall. One advantage of the local alarm is its low cost. Another is that a ringing bell lets the intruder know that his intrusion has been detected and may have second thoughts about completing the job.

Unlike the seismic sensor, (where the intruder is not aware he has tripped an alarm), there may be some benefit when the intruder is aware of the fact that his presence is known, or shortly will be known. Conversely when an intruder crosses a beam detection system, he does not know that an alarm has been tripped. Seconds later he is moving deeper into the protected area possibly to be apprehended. The major benefit gained from an audible signal is the fact that a watchman or other type of security person need not stare at a panel of lights for his entire duty period. The audible system calls immediate attention to an intrusion. Whereas a non-audible device is only as valuable as the time factor involved for the guard or watchman to observe the sensor's readout on the monitoring panel. The simplest unit is the local alarm which can be transmitted to a central security or police station. This demands transmission of the alarm signal over a communications link, usually leased, or through the media of telephone lines engineered for signal transmission.

14.8.5 Commercial/Central Station Connected Alarms

Central station alarms refer to security stations operated by companies which sell such services to manufacturers, banks, and other facilties in their market area. Direct connections via telephone lines to a central reporting and investigative unit are available in most communities throughout the United States. The units are monitored continually and when an alarm is received, the guard generally telephones the police and/or dispatches security personnel to the secured area. Incidents are reported as soon as possible to the customer.

Figures 14-38 and 14-39 illustrate modular security systems currently available for industrial purchase and rental. The systems provide state-of-the-art advancements in automated security. Typical modular security systems would offer the following.

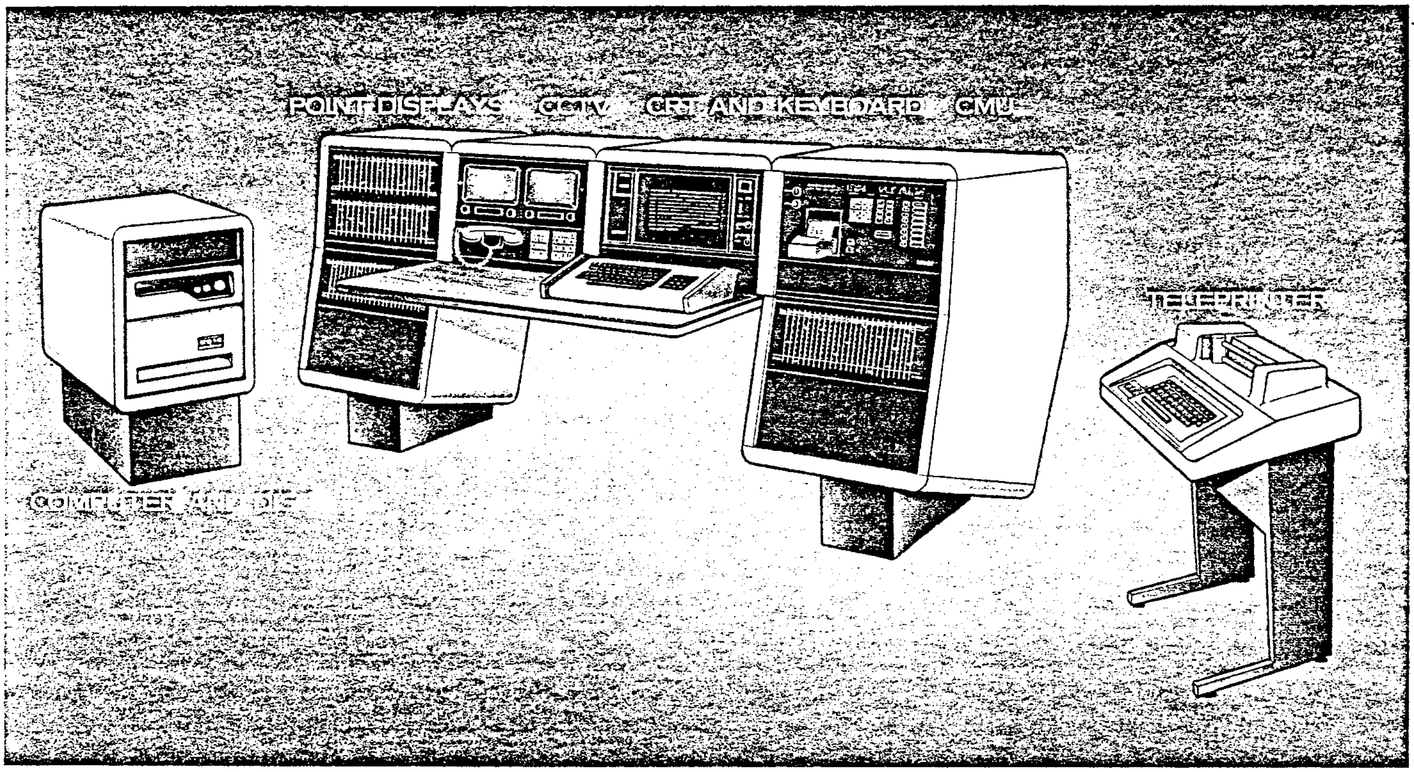


FIGURE 14-38. Mosler Corporation Modular Security System BRM-2

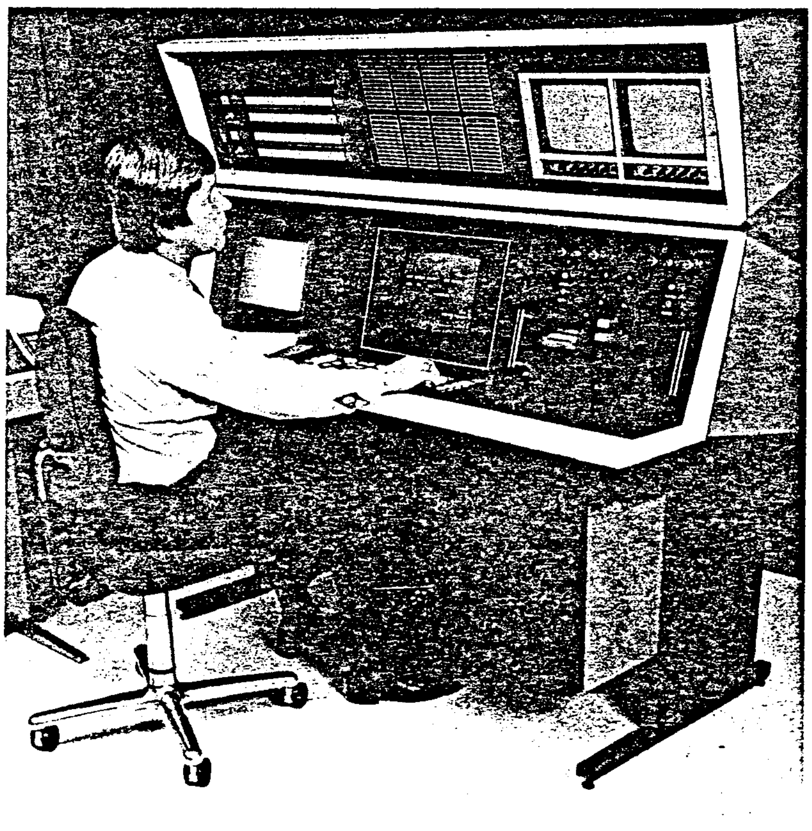


FIGURE 14-39. American District Telegraph (ADT) CentraScan 73 Central Security Module

- Visual Display - Cathode Ray Tube (CRT) screen showing keyboard command entries, alarms, and change of status with date and time.
- Command Entry Panel - Keyboard controls on/off, increase/decrease, access/secure and status summary.
- Line Printer - Hard copy printout of all commands, changes in status, alarm logs with times and dates.
- Control Processing Unit - Interrogates and receiver responses, micro- or mini-computers interpret alarms and operate remote devices.
- Closed circuit television security surveillance management control; video tape recording with date/time generator.
- Matrix Status Display - Constant summary, red for alarm, yellow for access, power failures and line trouble
- Programming CRT.
- Slide Projector - Allows visual display of alarm location with map and instructions for action.
- High Speed Printer - Full activity reporting. Records all changes of state, alarms, and logs.
- Standby Battery - Power backup keeps the central computer and the matrix display working in power failures of up to 72 hours.
- Software Programs - Energy management, load shedding, watchtour, automatic access/secure, card access, log/

command sequence, self check watchlog, emergency data file, analog monitoring and central station interaction.

These console units can support over 3,000 monitoring and control points and can be expanded to 7,000 as facility demands increase. The console units monitor not only alarms but also monitors lights, heating, refrigeration, and air-conditioning, AC power, and anything that can provide a set of normally open or cloased contacts.

Costing for these modular units varies so greatly that ADT Corporation, a specialist in security systems, could not give a fixed cost. Costing depends on location, size, and selection of monitoring stations needed for a specific facility.

14.9 Summation

The price of hydrocarbon products is soaring to stratospheric heights and losses of equipment and products from theft is growing in proportion. A multi-million dollar market has developed in stolen materials and operational equipment. This is aggrevated by damage to property in successful and unsuccessful attempts to gain access to short supply materials.

Thieves with ingenious methods are outwitting the oil industry and materials stolen in one state are being sold in another. The theft of oil has become a major problem challenging oil company security personnel.

Preventive measures can insure that theft of product can be held to a basic minimum (it cannot control inplant misappropriation of product). It is hoped that the content of this report section will enlighten plant operators to a burgeoning problem and provide a degree of preventive knowledge that will ultimately control the situation.

References:

Section 14. Plant Security

Schwartz, Allan, E. (undated.) Management Guide to CCTV Security Systems. American District Telegraph (ADT) Security Systems, 18 p.

Mosler Safe Company. (undated.) Guide to Electronic Alarm Systems, Mosler Safe Company.

Security Distributing and Marketing. June, 1980. "Finding Profits in Perimeter Protection." PP. 20-30.

Stanley, Arthur, T. 1978. Security Systems Analysis. Man Barrier Corporation. September 26.

Man Barrier Corporation. (undated.) Prison Security. Man Barrier Corporation.

Stanley, Arthur, T. 1974. Barrier Potential of Chain Link Fence. U.S. Army Mobility Equipment Research and Development Center. Fort Belvoir, Virginia. Report 2106

Stanley, Arthur, T. 1973. General-Purpose Barbed Tape Obstacle. U.S. Army Mobility Equipment Research and Development Center. Fort Belvoir, Virginia. Report 2077

Kodlick, Martin, R. 1978. Barrier Technology: Perimeter Barrier Penetration Tests. Sandia Laboratories, Albuquerque, New Mexico.

Industrial Risk Insurers. 1979. When the Plant Guard Takes Over. Hartford, Connecticut.

Industrial Risk Insurers. 1979. Truck Loading Rack Safety. Hartford, Connecticut.

American Petroleum Institute. 1975. Precautions Against Electrostatic Ignition During Loading of Tank Truck Motor Vehicles. Second Edition. Bulletin 1003.

Security World. November, 1979. "Oil Industry Sleuths: Crime Prevention from Oil Rig to Pump." pp. 16-19.

Meetings: R. J. Siclari with representatives from American District Telegraph (ADT), Mosler Safe Company, Man Barrier Corporation, General Electric Company, Hi-Tek Lighting and Sting Security Company.

Manufacturers' sales literature---(as per each unit described).

APPENDIX A

Copy of SPCC Regulation

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER D—WATER PROGRAMS

PART 112—OIL POLLUTION PREVENTION

Non-transportation Related Onshore and Offshore Facilities

Notice of proposed rule making was published on July 19, 1973, containing proposed regulations, required by an pursuant to section 311(j)(1)(C) of the Federal Water Pollution Control Act, as amended (86 Stat. 868, 33 U.S.C. 1251 et seq.), (FWPCA), to prevent discharges of oil into the navigable waters of the United States and to contain such discharges if they occur. The proposed regulations endeavor to prevent such spills by establishing procedures, methods and equipment requirements of owners or operators of facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, or consuming oil.

Written comments on the proposed regulations were solicited and received from interested parties. In addition, a number of verbal comments on the proposal were also received. The written comments are on file at the Division of Oil and Hazardous Materials, Office of Water Program Operations, U.S. Environmental Protection Agency, Washington, D.C.

All of the comments have been given careful consideration and a number of changes have been made in the regulation. These changes incorporate either suggestions made in the comments or ideas initiated by the suggestions.

Some comments reflected a misunderstanding of the fundamental principles of the regulation, specifically as they applied to older facilities and marginal operations. During the development of the regulation it was recognized that no single design or operational standard can be prescribed for all non-transportation related facilities, since the equipment and operational procedures appropriate for one facility may not be appropriate for another because of factors such as function, location, and age of each facility. Also, new facilities could achieve a higher level of spill prevention than older facilities by the use of fail-safe design concepts and innovative spill prevention methods and procedures. It was concluded that older facilities and marginal operations could develop strong spill contingency plans and commit manpower, oil containment devices and removal equipment to compensate for inherent weaknesses in the spill prevention plan.

Appropriate changes were made in the regulation to simplify, clarify or correct deficiencies in the proposal.

A discussion of these changes, section by section follows:

A. *Section 112.1—General applicability.* Section 112.1(b), the "foreseeability provision", contained in 112.1(d)(4) was added to paragraph 112.1(b). As modified, the regulation applies to non-transportation-related onshore and offshore facilities which, due to their location, could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines.

Sections 112.1(b), 112.1(d)(4) and 112.3 are now consistent.

Section 112.1(d)(1) was expanded to further clarify the respective authorities of the Department of Transportation and the Environmental Protection Agency by referring to the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency (Appendix).

Section 112.1(d)(2), the figure for barrels was converted to gallons, a unit of measure more familiar to the public, and now reads "42000 gallons."

Section 112.1(d)(3), exemption for facilities with nonburied tankage was extended to 1320 gallons in aggregate with no single tank larger than 660 gallons and applies to all oils, not just heating oil and motor fuel. Tanks of 660 gallons are the normal domestic code size for nonburied heating oil tanks. Buildings may have two such tanks. Facilities containing small quantities of oil other than motor fuel or heating oil would also be exempt, thus making this consistent with the definition of oil in § 112.2.

B. *Section 112.2—Definitions.* Section 112.2(1), the term "navigable waters" was expanded to the more descriptive definition used by the National Pollutant Discharge Elimination System.

Section 112.2(m), the U.S. Coast Guard definition of the term "vessel" was included. This term is used in the regulation and the definition is consistent with the Department of Transportation regulations.

C. *Section 112.3—Requirements for the preparation and implementation of spill prevention control and countermeasure plans.* A new paragraph (c) was added to § 112.3 which applies to mobile or portable facilities subject to the regulation. These facilities need not prepare a new Spill Prevention Control and Countermeasure Plan (SPCC Plan) each time the facility is moved to a new site, but may prepare a general plan, identifying good spill prevention engineering practices (as outlined in the guidelines, § 112.7), and implement these practices at each new location.

Section 112.3(a), (b) and (f) (which was § 112.3(e) in the proposed rule making) have been modified to allow extensions of time beyond the normally specified periods to apply to the preparation of plans as well as to their implementation and to remove the time limitation of one year for extensions. Extensions may be allowed for whatever period of time considered reasonable by the Regional Administrator.

Section 112.3(e) (which was § 112.3(d) in the proposed rule making) was modified to require the maintenance of the SPCC Plan for inspection at the facility only if the facility was normally manned. If the facility is unmanned, the Plan may be kept at the nearest field office.

Section 112.3(f)(1) (§ 112.3(e)(1) in the proposed regulation) was changed to include the nonavailability of qualified personnel as a reason for the Regional Administrator granting an extension of time.

D. *Section 112.4—Amendment of spill prevention control and countermeasure plans by Regional Administrator.* Section 112.4(a)(11), permits the Regional Administrator to require that the owner or operator furnish additional information to EPA after one or more spill event has occurred. The change limits the request for additional information to that pertinent to the SPCC Plan or to the pollution incident.

Section 112.4(b) now reads "Section 112.4 * * *", not "This subsection * * *"

Section 112.4(e) allowed the Regional Administrator to require amendments to SPCC Plans and specifies that the amendment must be incorporated in the Plan within 30 days unless the Regional Administrator specifies an earlier effective date. The change allows the Regional Administrator to specify any appropriate date that is reasonable.

Section 112.4(f). A new § 112.4(f) has been added which provides for an appeal by an owner or operator from a decision rendered by the Regional Administrator on an amendment to an SPCC Plan. The appeal is made to the Administrator of EPA and the paragraph outlines the procedures for making such an appeal.

E. *Section 112.5—Amendment of spill prevention control and countermeasure plans by owners or operators.* Section 112.5(b) required the owner or operator to amend the SPCC Plan every three years. The amendment required the incorporation of any new, field-proven technology and had to be certified by a Professional Engineer.

The change requires that the owner or operator review the Plan every three years to see if it needs amendment. New technology need be incorporated only if it will significantly reduce the likelihood of a spill. The change will prevent frivolous retrofitting of equipment to facilities whose prevention plans are working successfully, and will not require engineering certification unless an amendment is necessary.

Section 112.5(c), this paragraph required that the owner or operator amend his SPCC Plan when his facility became subject to §112.4 (amendment by the Regional Administrator). This paragraph has been removed. It is inconsistent to require the owner or operator to independently amend the Plan while the Regional Administrator is reviewing it for possible amendment.

F. *Section 112.6—Civil penalties.* There are no changes in this section.

G. *Section 112.7—Guidelines for the preparation and implementation of a spill prevention control and countermeasure plan.* Numerous changes have been made in the guidelines section; the changes have been primarily:

1. To correct the use of language inconsistent with guidelines. For example, the word "shall" has been changed to "should" in § 112.7(a) through (e).

2. To give the engineer preparing the Plan greater latitude to use alternative methods better suited to a given facility or local conditions.

3. To cover facilities subject to the regulation, but for which no guidelines were previously given. This category includes such things as mobile facilities, and drilling and workover rigs.

In addition, wording was changed to differentiate between periodic observations by operating personnel and formal inspections with attendant record keeping.

These regulations shall become effective January 10, 1974.

Dated: November 27, 1973.

JOHN QUARLES,
Acting Administrator.

A new Part 112 would be added to subchapter D, Chapter I of Title 40, Code of Federal Regulations as follows:

Sec.
112.1 General applicability.
112.2 Definitions.
112.3 Requirements for preparation and implementation of Spill Prevention Control and Countermeasure plans.
112.4 Amendment of Spill Prevention Control and Countermeasure Plans by Regional Administrator.
112.5 Admendment of Spill Prevention Control and Countermeasure Plans by owners or operators.
112.6 Civil penalties.
112.7 Guidelines for the preparation and implementation of a Spill Prevention Control and Countermeasure Plan.
Appendix Memorandum of Understanding Between the Secretary of the Department of Transportation and the Administrator of the Environmental Protection Agency. Section II—Definitions.

AUTHORITY: Secs. 311(j)(1)(C), 311(j)(2), 501(a), Federal Water Pollution Control Act (Sec. 2, Pub. L. 92-500, 86 Stat. 816 et seq. (33 U.S.C. 1251 et seq.)); Sec. 4(b), Pub. L. 92-500, 86 Stat. 897; 5 U.S.C. Reorg. Plan of 1970 No. 3 (1970), 35 FR 15623, 3 CFR 1966-1970 Comp.; E.O. 11735, 38 FR 21243, 3 CFR.

§ 112.1 General applicability.

(a) This part establishes procedures, methods and equipment and other requirements for equipment to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines.

(b) Except as provided in paragraph (d) of this section, this part applies to owners or operators of non-transportation-related onshore and offshore facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing or consuming oil and oil products, and which, due to their location, could reasonably be expected to discharge oil in harmful quantities, as defined in Part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines.

(c) As provided in sec. 313 (86 Stat. 875) departments, agencies, and instrumentalities of the Federal government are subject to these regulations to the same extent as any person, except for the provisions of § 112.6.

(d) This part does not apply to:

(1) Equipment or operations of vessels or transportation-related onshore and offshore facilities which are subject to authority and control of the Department of Transportation, as defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, 36 FR 24000.

(2) Facilities which have an aggregate storage of 1320 gallons or less of oil, provided no single container has a capacity in excess of 660 gallons.

(3) Facilities which have a total storage capacity of 42000 gallons or less of oil and such total storage capacity is buried underground.

(4) Non-transportation-related onshore and offshore facilities, which, due to their location, could not reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines.

(e) This part provides for the preparation and implementation of Spill Prevention Control and Countermeasure Plans prepared in accordance with § 112.7, designed to complement existing laws, regulations, rules, standards, policies and procedures pertaining to safety standards, fire prevention and pollution prevention rules, so as to form a comprehensive balanced Federal/State spill prevention program to minimize the potential for oil discharges. Compliance with this part does not in any way relieve the owner or operator of an onshore or an offshore facility from compliance with other Federal, State or local laws.

§ 112.2 Definitions.

For the purposes of this part:

(a) "Oil" means oil of any kind or in any form, including, but not limited to petroleum, fuel oil, sludge, oil refuse and oil mixed with wastes other than dredged spoil.

(b) "Discharge" includes but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying or dumping. For purposes of this part, the term "discharge" shall not include any discharge of oil which is authorized by a permit issued pursuant to Section 13 of the River and Harbor Act of 1899 (30 Stat. 1121, 33 U.S.C. 407), or Sections 402 or 405 of the FWPCA Amendments of 1972 (86 Stat. 816 et seq., 33 U.S.C. 1251 et seq.).

(c) "Onshore facility" means any facility of any kind located in, on, or under any land within the United States, other than submerged lands, which is not a transportation-related facility.

(d) "Offshore facility" means any facility of any kind located in, on, or under any of the navigable waters of the United States, which is not a transportation-related facility.

(e) "Owner or operator" means any person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated such facility immediately prior to such abandonment.

(f) "Person" includes an individual, firm, corporation, association, and a partnership.

(g) "Regional Administrator", means the Regional Administrator of the Environmental Protection Agency, or his designee, in and for the Region in which the facility is located.

(h) "Transportation-related" and "non-transportation-related" as applied to an onshore or offshore facility, are defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, 36 FR 24080.

(i) "Spill event" means a discharge of oil into or upon the navigable waters of the United States or adjoining shorelines in harmful quantities, as defined at 40 CFR Part 110.

(j) "United States" means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Canal Zone, Guam, American Samoa, the Virgin Islands, and the Trust Territory of the Pacific Islands.

(k) The term "navigable waters" of the United States means "navigable waters" as defined in section 502(7) of the FWPCA, and includes:

(1) all navigable waters of the United States, as defined in judicial decisions prior to passage of the 1972 Amendments to the FWPCA (Pub. L. 92-500), and tributaries of such waters;

(2) interstate waters;

(3) intrastate lakes, rivers, and streams which are utilized by interstate travelers for recreational or other purposes; and

(4) intrastate lakes, rivers, and streams from which fish or shellfish are taken and sold in interstate commerce.

(l) "Vessel" means every description of watercraft or other artificial contrivance used, or capable of being used as a means of transportation on water, other than a public vessel.

§ 112.3 Requirements for preparation and implementation of Spill Prevention Control and Countermeasure Plans.

(a) Owners or operators of onshore and offshore facilities in operation on or before the effective date of this part that have discharged or could reasonably be expected to discharge oil in harmful quantities, as defined in 40 CFR Part 110, into or upon the navigable waters of the United States or adjoining shorelines, shall prepare a Spill Prevention Control and Countermeasure Plan (hereinafter "SPCC Plan"), in accordance with § 112.7. Except as provided for in paragraph (f) of this section, such SPCC Plan shall be prepared within six months after the effective date of this part and shall be fully implemented as soon as possible, but not later than one year after the effective date of this part.

(b) Owners or operators of onshore and offshore facilities that become operational after the effective date of this part, and that have discharged or could reasonably be expected to discharge oil in harmful quantities, as defined in 40 CFR Part 110, into or upon the navigable waters of the United States or adjoining shorelines, shall prepare an SPCC Plan in accordance with § 112.7. Except as provided for in paragraph (f) of this section, such SPCC Plan shall be prepared within six months after the date such facility begins operations and shall be fully implemented as soon as possible, but not later than one year after such facility begins operations.

(c) Onshore and offshore mobile or portable facilities such as onshore drilling or workover rigs, barge mounted offshore drilling or workover rigs, and portable fueling facilities shall prepare and implement an SPCC Plan as required by paragraphs (a), (b) and (d) of this section. The owner or operator of such facility need not prepare and implement a new SPCC-Plan each time the facility is moved to a new site. The SPCC Plan for mobile facilities should be prepared in accordance with § 112.7, using good engineering practice, and when the mobile facility is moved it should be located and installed using spill prevention practices outlined in the SPCC Plan for the facility. The SPCC Plan shall only apply while the facility is in a fixed (non transportation) operating mode.

(d) No SPCC Plan shall be effective to satisfy the requirements of this part unless it has been reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. By means of this certification the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the SPCC Plan has been prepared in accordance with good engineering practices. Such certification shall in no way relieve the owner or operator of an onshore or offshore facility of his duty to prepare and fully implement such Plan in accordance with § 112.7, as required by paragraphs (a), (b) and (c) of this section.

(e) Owners or operators of a facility for which an SPCC Plan is required pursuant to paragraphs (a), (b) or (c) of this section shall maintain a complete copy of the Plan at such facility if the facility is normally attended at least 8 hours per day, or at the nearest field office if the facility is not so attended, and shall make such Plan available to the Regional Administrator for on-site review during normal working hours.

(f) Extensions of time.

(1) The Regional Administrator may authorize an extension of time for the preparation and full implementation of an SPCC Plan beyond the time permitted for the preparation and implementation of an SPCC Plan pursuant to paragraphs (a), (b) or (c) of this section where he finds that the owner or operator of a facility subject to paragraphs (a), (b) or (c) of this section cannot fully comply with the requirements of this part as a result of either nonavailability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of such owner or operator or their respective agents or employees.

(2) Any owner or operator seeking an extension of time pursuant to paragraph (f)(1) of this section may submit a letter of request to the Regional Administrator. Such letter shall include:

(i) A complete copy of the SPCC Plan, if completed;

(ii) A full explanation of the cause for any such delay and the specific aspects of the SPCC Plan affected by the delay;

(iii) A full discussion of actions being taken or contemplated to minimize or mitigate such delay;

(iv) A proposed time schedule for the implementation of any corrective actions being taken or contemplated, including interim dates for completion of tests or studies, installation and operation of any necessary equipment or other preventive measures.

In addition, such owner or operator may present additional oral or written statements in support of his letter of request.

(3) The submission of a letter of request for extension of time pursuant to paragraph (f)(2) of this section shall in no way relieve the owner or operator from his obligation to comply with the requirements of § 112.3 (a), (b) or (c). Where an extension of time is authorized by the Regional Administrator for particular equipment or other specific aspects of the SPCC Plan, such extension shall in no way affect the owner's or operator's obligation to comply with the requirements of § 112.3 (a), (b) or (c) with respect to other equipment or other specific aspects of the SPCC Plan for which an extension of time has not been expressly authorized.

§ 112.4 Amendment of SPCC Plans by Regional Administrator.

(a) Notwithstanding compliance with § 112.3, whenever a facility subject to § 112.3 (a), (b) or (c) has: Discharged more than 1,000 U.S. gallons of oil into or upon the navigable waters of the United States or adjoining shorelines in a single spill event, or discharged oil in harmful quantities, as defined in 40 CFR Part 110, into or upon the navigable waters of the United States or adjoining shorelines in two spill events, reportable under section 311(b)(5) of the FWPCA, occurring within any twelve month period, the owner or operator of such facility shall submit to the Regional Administrator, within 60 days from the time such facility becomes subject to this section, the following:

(1) Name of the facility;

(2) Name(s) of the owner or operator of the facility;

(3) Location of the facility;

(4) Date and year of initial facility operation;

(5) Maximum storage or handling capacity of the facility and normal daily throughput;

(6) Description of the facility, including maps, flow diagrams, and topographical maps;

(7) A complete copy of the SPCC Plan with any amendments;

(8) The cause(s) of such spill, including a failure analysis of system or subsystem in which the failure occurred;

(9) The corrective actions and/or countermeasures taken, including an adequate description of equipment repairs and/or replacements;

(10) Additional preventive measures taken or contemplated to minimize the possibility of recurrence;

(11) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or spill event.

(b) Section 112.4 shall not apply until the expiration of the time permitted for the preparation and implementation of an SPCC Plan pursuant to § 112.3 (a), (b), (c) and (f).

(c) A complete copy of all information provided to the Regional Administrator pursuant to paragraph (a) of this section shall be sent at the same time to the State agency in charge of water pollution control activities in and for the State in which the facility is located. Upon receipt of such information such State agency may conduct a review and make recommendations to the Regional Administrator as to further procedures, methods, equipment and other requirements for equipment necessary to prevent and to contain discharges of oil from such facility.

(d) After review of the SPCC Plan for a facility subject to paragraph (a) of this section, together with all other information submitted by the owner or operator of such facility, and by the State agency under paragraph (c) of this section, the Regional Administrator may require the owner or operator of such facility to amend the SPCC Plan if he finds that the Plan does not meet the requirements of this part or that the amendment of the Plan is necessary to prevent and to contain discharges of oil from such facility.

(e) When the Regional Administrator proposes to require an amendment to the SPCC Plan, he shall notify the facility operator by certified mail addressed to, or by personal delivery to, the facility owner or operator, that he proposes to require an amendment to the Plan, and shall specify the terms of such amendment. If the facility owner or operator is a corporation, a copy of such notice shall also be mailed to the registered agent, if any, of such corporation in the State where such facility is located. Within 30 days from receipt of such notice, the facility owner or operator may submit written information, views, and arguments on the amendment. After considering all relevant material presented, the Regional Administrator shall notify the facility owner or operator of any amendment required or shall rescind the notice. The amendment required by the Regional Administrator shall become part of the Plan 30 days tank should be used for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature, etc.

(ii) All bulk storage tank installations should be constructed so that a secondary means of containment is provided for the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation. Diked areas should be sufficiently impervious to contain spilled oil. Dikes, containment curbs, and pits are commonly employed for this purpose, but they may not always be appropriate. An alternative system could consist of a complete drainage trench enclosure arranged so that a spill could terminate and be safely confined in an in-plant catchment basin or holding pond.

(iii) Drainage of rainwater from the diked area into a storm drain or an effluent discharge that empties into an open water course, lake, or pond, and bypassing the in-plant treatment system may be acceptable if:

(A) The bypass valve is normally sealed closed.

(B) Inspection of the run-off rain water ensures compliance with applicable water quality standards and will not cause a harmful discharge as defined in 40 CFR 110.

(C) The bypass valve is opened, and resealed following drainage under responsible supervision.

(D) Adequate records are kept of such events.

(iv) Buried metallic storage tanks represent a potential for undetected spills. A new buried installation should be protected from corrosion by coatings, cathodic protection or other effective methods compatible with local soil conditions. Such buried tanks should at least be subjected to regular pressure testing.

(v) Partially buried metallic tanks for the storage of oil should be avoided, unless the buried section of the shell is adequately coated, since partial burial in damp earth can cause rapid corrosion of metallic surfaces, especially at the earth/air interface.

(vi) Aboveground tanks should be subject to periodic integrity testing, taking into account tank design (floating roof, etc.) and using such techniques as hydrostatic testing, visual inspection or a system of non-destructive shell thickness testing. Comparison records should be kept where appropriate, and tank supports and foundations should be included in these inspections. In addition, the outside of the tank should frequently be observed by operating personnel for signs of deterioration, leaks which might cause a spill, or accumulation of oil inside diked areas.

(vii) To control leakage through defective internal heating coils, the following factors should be considered and applied, as appropriate.

(A) The steam return or exhaust lines from internal heating coils which discharge into an open water course should be monitored for contamination, or passed through a settling tank, skimmer, or other separation or retention system.

(B) The feasibility of installing an external heating system should also be considered.

(viii) New and old tank installations should, as far as practical, be fail-safe engineered or updated into a fail-safe engineered installation to avoid spills. Consideration should be given to providing one or more of the following devices:

(A) High liquid level alarms with an audible or visual signal at a constantly manned operation or surveillance station; in smaller plants an audible air vent may suffice.

(B) Considering size and complexity of the facility, high liquid level pump cutoff devices set to stop flow at a predetermined tank content level.

(C) Direct audible or code signal communication between the tank gauger and the pumping station.

(D) A fast response system for determining the liquid level of each bulk storage tank such as digital computers, telepulse, or direct vision gauges or their equivalent.

(E) Liquid level sensing devices should be regularly tested to insure proper operation.

(ix) Plant effluents which are discharged into navigable waters should have disposal facilities observed frequently enough to detect possible system upsets that could cause an oil spill event.

(x) Visible oil leaks which result in a loss of oil from tank seams, gaskets, rivets and bolts sufficiently large to cause the accumulation of oil in diked areas should be promptly corrected.

(xi) Mobile or portable oil storage tanks (onshore) should be positioned or located so as to prevent spilled oil from reaching navigable waters. A secondary means of containment, such as dikes or catchment basins, should be furnished for the largest single compartment or tank. These facilities should be located where they will not be subject to periodic flooding or washout.

(3) *Facility transfer operations, pumping, and in-plant process (onshore); (excluding production facilities)*. (i) Buried piping installations should have a protective wrapping and coating and should be cathodically protected if soil conditions warrant. If a section of buried line is exposed for any reason, it should be carefully examined for deterioration. If corrosion damage is found, additional examination and corrective action should be taken as indicated by the magnitude of the damage. An alternative would be the more frequent use of exposed pipe corridors or galleries.

(ii) When a pipeline is not in service, or in standby service for an extended time the terminal connection at the transfer point should be capped or blank-flanged, and marked as to origin.

(iii) Pipe supports should be properly designed to minimize abrasion and corrosion and allow for expansion and contraction.

(iv) All aboveground valves and pipelines should be subjected to regular examinations by operating personnel at which time the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces should be assessed. In addition, periodic pressure testing may be warranted for piping in areas where facility drainage is such that a failure might lead to a spill event.

(v) Vehicular traffic granted entry into the facility should be warned verbally or by appropriate signs to be sure that the vehicle, because of its size, will not endanger above ground piping.

(4) *Facility tank car and tank truck loading/unloading rack (onshore)*. (i) Tank car and tank truck loading/unloading procedures should meet the minimum requirements and regulation established by the Department of Transportation.

(ii) Where rack area drainage does not flow into a catchment basin or treatment facility designed to handle spills, a quick drainage system should be used for tank truck loading and unloading areas. The containment system should be designed to hold at least maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded in the plant.

(iii) An interlocked warning light or physical barrier system, or warning signs, should be provided in loading/unloading areas to prevent vehicular departure before complete disconnect of flexible or fixed transfer lines.

(iv) Prior to filling and departure of any tank car or tank truck, the lowermost drain and all outlets of such vehicles should be closely examined for leakage, and if necessary, tightened, adjusted, or replaced to prevent liquid leakage while in transit.

(5) *Oil production facilities (onshore)*. (i) *Definition*. An onshore production facility may include all wells, flowlines, separation equipment, storage facilities, gathering lines, and auxiliary non-transportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator.

(ii) *Oil production facility (onshore) drainage*. (A) At tank batteries and central treating stations where an accidental discharge of oil would have a reasonable possibility of reaching navigable waters, the dikes or equivalent required under § 112.7(c)(1) should have drains closed and sealed at all times except when rainwater is being drained. Prior to drainage, the diked area should be inspected as provided in paragraph (e)(2)(iii) (B), C), and (D). Accumulated oil on the rainwater should be picked up and returned to storage or disposed of in accordance with approved methods.

(B) Field drainage ditches, road ditches, and oil traps, sumps or skimmers, if such exist, should be inspected at regularly scheduled intervals for accumulation of oil that may have escaped from small leaks. Any such accumulations should be removed.

(iii) *Oil production facility (onshore) bulk storage tanks*. (A) No tank should be used for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

after such notice, unless the Regional Administrator, for good cause, shall specify another effective date. The owner or operator of the facility shall implement the amendment of the Plan as soon as possible, but not later than six months after the amendment becomes part of the Plan, unless the Regional Administrator specifies another date.

(f) An owner or operator may appeal a decision made by the Regional Administrator requiring an amendment to an SPCC Plan. The appeal shall be made to the Administrator of the United States Environmental Protection Agency and must be made in writing within 30 days of receipt of the notice from the Regional Administrator requiring the amendment. A complete copy of the appeal must be sent to the Regional Administrator at the time the appeal is made. The appeal shall contain a clear and concise statement of the issues and points of fact in the case. It may also contain additional information which the owner or operator wishes to present in support of his argument. The Administrator or his designee may request additional information from the owner or operator, or from any other person. The Administrator or his designee may request additional information from the owner or operator, or from any other person. The Administrator or his designee shall render a decision within 60 days of receiving the appeal and shall notify the owner or operator of his decision.

§ 112.5 Amendment of Spill Prevention Control and Countermeasure Plans by owners or operators.

(a) Owners or operators of facilities subject to § 112.3 (a), (b) or (c) shall amend the SPCC Plan for such facility in accordance with § 112.7 whenever there is a change in facility design, construction, operation or maintenance which materially affects the facility's potential for the discharge of oil into or upon the navigable waters of the United States or adjoining shorelines. Such amendments shall be fully implemented as soon as possible, but not later than six months after such change occurs.

(b) Notwithstanding compliance with paragraph (a) of this section, owners and operators of facilities subject to § 112.3 (a), (b) or (c) shall complete a review and evaluation of the SPCC Plan at least once every three years from the date such facility becomes subject to this part. As a result of this review and evaluation, the owner or operator shall amend the SPCC Plan within six months of the review to include more effective prevention and control technology if: (1) Such technology will significantly reduce the likelihood of a spill event from the facility, and (2) if such technology has been field-proven at the time of the review.

(c) No amendment to an SPCC Plan shall be effective to satisfy the requirements of this section unless it has been certified by a Professional Engineer in accordance with § 112.3(d).

§ 112.6 Civil penalties.

Owners or operators of facilities subject to § 112.3 (a), (b) or (c) who violate the requirements of this part by failing or refusing to comply with any of the provisions of § 112.3, § 112.4, or § 112.5 shall be liable for a civil penalty of not more than $5,000 for each day that such violation continues. The Regional Administrator may assess and compromise such civil penalty. No penalty shall be assessed until the owner or operator shall have been given notice and an opportunity for hearing.

§ 112.7 Guidelines for the preparation and implementation of a Spill Prevention Control and Countermeasure Plan.

The SPCC Plan shall be a carefully thought-out plan, prepared in accordance with good engineering practices, and which has the full approval of management at a level with authority to commit the necessary resources. If the plan calls for additional facilities or procedures, methods, or equipment not yet fully operational, these items should be discussed in separate paragraphs, and the details of installation and operational start-up should be explained separately. The complete SPCC Plan shall follow the sequence outlined below, and include a discussion of the facility's conformance with the appropriate guidelines listed:

(a) A facility which has experienced one or more spill events within twelve months prior to the effective date of this part should include a written description of each such spill, corrective action taken and plans for preventing recurrence.

(b) Where experience indicates a reasonable potential for equipment failure (such as tank overflow, rupture, or leakage), the plan should include a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each major type of failure.

(c) Appropriate containment and/or diversionary structures or equipment to prevent discharged oil from reaching a navigable water course should be provided. One of the following preventive systems or its equivalent should be used as a minimum:

(1) Onshore facilities.

(i) Dikes, berms or retaining walls sufficiently impervious to contain spilled oil

(ii) Curbing

(iii) Culverting, gutters or other drainage systems

(iv) Weirs, booms or other barriers

(v) Spill diversion ponds

(vi) Retention ponds

(vii) Sorbent materials

(2) Offshore facilities.

(i) Curbing, drip pans

(ii) Sumps and collection systems

(d) When it is determined that the installation of structures or equipment listed in § 112.7(c) to prevent discharged oil from reaching the navigable waters is not practicable from any onshore or offshore facility, the owner or operator should clearly demonstrate such impracticability and provide the following:

(1) A strong oil spill contingency plan following the provision of 40 CFR Part 109.

(2) A written commitment of manpower, equipment and materials required to expeditiously control and remove any harmful quantity of oil discharged.

(e) In addition to the minimal prevention standards listed under § 112.7 (c), sections of the Plan should include a complete discussion of conformance with the following applicable guidelines, other effective spill prevention and containment procedures (or, if more stringent, with State rules, regulations and guidelines):

(1) *Facility drainage (onshore); (excluding production facilities)*. (i) Drainage from diked storage areas should be restrained by valves or other positive means to prevent a spill or other excessive leakage of oil into the drainage system or inplant effluent treatment system, except where plan systems are designed to handle such leakage. Diked areas may be emptied by pumps or ejectors; however, these should be manually activated and the condition of the accumulation should be examined before starting to be sure no oil will be discharged into the water.

(ii) Flapper-type drain valves should not be used to drain diked areas. Valves used for the drainage of diked areas should, as far as practical, be of manual, open-and-closed design. When plant drainage drains directly into water courses and not into wastewater treatment plants, retained storm water should be inspected as provided in paragraph (e)(2)(iii) (B, C and D) before drainage.

(iii) Plant drainage systems from undiked areas should, if possible, flow into ponds, lagoons or catchment basins, designed to retain oil or return it to the facility. Catchment basins should not be located in areas subject to periodic flooding.

(iv) If plant drainage is not engineered as above, the final discharge of all in-plant ditches should be equipped with a diversion system that could, in the event of an uncontrolled spill, return the oil to the plant.

(v) Where drainage waters are treated in more than one treatment unit, natural hydraulic flow should be used. If pump transfer is needed, two "lift" pumps should be provided, and at least one of the pumps should be permanently installed when such treatment is continuous. In any event, whatever techniques are used facility drainage systems should be adequately engineered to prevent oil from reaching navigable waters in the event of equipment failure or human error at the facility.

(2) *Bulk storage tanks (onshore); (excluding production facilities)*. (i) No

(B) All tank battery and central treating plant installations should be provided with a secondary means of containment for the entire contents of the largest single tank if feasible, or alternate systems such as those outlined in § 112.7(c)(1). Drainage from undiked areas should be safely confined in a catchment basin or holding pond.

(C) All tanks containing oil should be visually examined by a competent person for condition and need for maintenance on a scheduled periodic basis. Such examination should include the foundation and supports of tanks that are above the surface of the ground.

(D) New and old tank battery installations should, as far as practical, be fail-safe engineered or updated into a fail-safe engineered installation to prevent spills. Consideration should be given to one or more of the following:

(*1*) Adequate tank capacity to assure that a tank will not overfill should a pumper/gauger be delayed in making his regular rounds.

(*2*) Overflow equalizing lines between tanks so that a full tank can overflow to an adjacent tank.

(*3*) Adequate vacuum protection to prevent tank collapse during a pipeline run.

(*4*) High level sensors to generate and transmit an alarm signal to the computer where facilities are a part of a computer production control system.

(iv) *Facility transfer operations, oil production facility (onshore)*. (A) All above ground valves and pipelines should be examined periodically on a scheduled basis for general condition of items such as flange joints, valve glands and bodies, drip pans, pipeline supports, pumping well polish rod stuffing boxes, bleeder and gauge valves.

(B) Salt water (oil field brine) disposal facilities should be examined often, particularly following a sudden change in atmospheric temperature to detect possible system upsets that could cause an oil discharge.

(C) Production facilities should have a program of flowline maintenance to prevent spills from this source. The program should include periodic examinations, corrosion protection, flowline replacement, and adequate records, as appropriate, for the individual facility.

(6) *Oil drilling and workover facilities (onshore)* (i) Mobile drilling or workover equipment should be positioned or located so as to prevent spilled oil from reaching navigable waters.

(ii) Depending on the location, catchment basins or diversion structures may be necessary to intercept and contain spills of fuel, crude oil, or oily drilling fluids.

(iii) Before drilling below any casing string or during workover operations, a blowout prevention (BOP) assembly and well control system should be installed that is capable of controlling any well head pressure that is expected to be encountered while that BOP assembly is on the well. Casing and BOP installations should be in accordance with State regulatory agency requirements.

(7) *Oil drilling, production, or workover facilities (offshore)*. (i) Definition: "An oil drilling, production or workover facility (offshore)" may include all drilling or workover equipment, wells, flowlines, gathering lines, platforms, and auxiliary nontransportation - related equipment and facilities in a single geographical oil or gas field operated by a single operator.

(ii) Oil drainage collection equipment should be used to prevent and control small oil spillage around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and allied equipment. Drains on the facility should be controlled and directed toward a central collection sump or equivalent collection system sufficient to prevent discharges of oil into the navigable waters of the United States. Where drains and sumps are not practicable oil contained in collection equipment should be removed as often as necessary to prevent overflow.

(iii) For facilities employing a sump system, sump and drains should be adequately sized and a spare pump or equivalent method should be available to remove liquid from the sump and assure that oil does not escape. A regular scheduled preventive maintenance inspection and testing program should be employed to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(iv) In areas where separators and treaters are equipped with dump valves whose predominant mode of failure is in the closed position and pollution risk is high, the facility should be specially equipped to prevent the escape of oil. This could be accomplished by extending the flare line to a diked area if the separator is near shore, equipping it with a high liquid level sensor that will automatically shut-in wells producing to the separator, parallel redundant dump valves, or other feasible alternatives to prevent oil discharges.

(v) Atmospheric storage or surge tanks should be equipped with high liquid level sensing devices or other acceptable alternatives to prevent oil discharges.

(vi) Pressure tanks should be equipped with high and low pressure sensing devices to activate an alarm and/or control the flow or other acceptable alternatives to prevent oil discharges.

(vii) Tanks should be equipped with suitable corrosion protection.

(viii) A written procedure for inspecting and testing pollution prevention equipment and systems should be prepared and maintained at the facility. Such procedures should be included as part of the SPCC Plan.

(ix) Testing and inspection of the pollution prevention equipment and systems at the facility should be conducted by the owner or operator on a scheduled periodic basis commensurate with the complexity, conditions and circumstances of the facility or other appropriate regulations.

(x) Surface and subsurface well shut-in valves and devices in use at the facility should be sufficiently described to determine method of activation or control, e.g., pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms. Detailed records for each well, while not necessarily part of the plan should be kept by the owner or operator.

(xi) Before drilling below any casing string, and during workover operations a blowout preventer (BOP) assembly and well control system should be installed that is capable of controlling any wellhead pressure that is expected to be encountered while that BOP assembly is on the well. Casing and BOP installations should be in accordance with State regulatory agency requirements.

(xii) Extraordinary well control measures should be provided should emergency conditions, including fire, loss of control and other abnormal conditions, occur. The degree of control system redundancy should vary with hazard exposure and probable consequences of failure. It is recommended that surface shut-in systems have redundant or "fail close" valving. Subsurface safety valves may not be needed in producing wells that will not flow but should be installed as required by applicable State regulations.

(xiii) In order that there will be no misunderstanding of joint and separate duties and obligations to perform work in a safe and pollution free manner, written instructions should be prepared by the owner or operator for contractors and subcontractors to follow whenever contract activities include servicing a well or systems appurtenant to a well or pressure vessel. Such instructions and procedures should be maintained at the offshore production facility. Under certain circumstances and conditions such contractor activities may require the presence at the facility of an authorized representative of the owner or operator who would intervene when necessary to prevent a spill event.

(xiv) All manifolds (headers) should be equipped with check valves on individual flowlines.

(xv) If the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves associated with that individual flowline, the flowline should be equipped with a high pressure sensing device and shutin valve at the wellhead unless provided with a pressure relief system to prevent over pressuring.

(xvi) All pipelines appurtenant to the facility should be protected from corrosion. Methods used, such as protective coatings or cathodic protection, should be discussed.

(xvii) Sub-marine pipelines appurtenant to the facility should be adequately protected against environmental stresses and other activities such as fishing operations.

(xviii) Sub-marine pipelines appurtenant to the facility should be in good operating condition at all times and inspected on a scheduled periodic basis for failures. Such inspections should be documented and maintained at the facility.

(8) *Inspections and records.* Inspections required by this part should be in accordance with written procedures developed for the facility by the owner or operator. These written procedures and a record of the inspections, signed by the appropriate supervisor or inspector, should be made part of the SPCC Plan and maintained for a period of three years.

(9) *Security (excluding oil production facilities).* (i) All plants handling, processing, and storing oil should be fully fenced, and entrance gates should be locked and/or guarded when the plant is not in production or is unattended.

(ii) The master flow and drain valves and any other valves that will permit direct outward flow of the tank's content to the surface should be securely locked in the closed position when in non-operating or non-standby status.

(iii) The starter control on all oil pumps should be locked in the "off" position or located at a site accessible only to authorized personnel when the pumps are in a non-operating or non-standby status.

(iv) The loading/unloading connections of oil pipelines should be securely capped or blank-flanged when not in service or standby service for an extended time. This security practice should also apply to pipelines that are emptied of liquid content either by draining or by inert gas pressure.

(v) Facility lighting should be commensurate with the type and location of the facility. Consideration should be given to: (A) Discovery of spills occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.) and (B) prevention of spills occurring through acts of vandalism.

(10) *Personnel, training and spill prevention procedures.* (i) Owners or operators are responsible for properly instructing their personnel in the operation and maintenance of equipment to prevent the discharges of oil and applicable pollution control laws, rules and regulations.

(ii) Each applicable facility should have a designated person who is accountable for oil spill prevention and who reports to line management.

(iii) Owners or operators should schedule and conduct spill prevention briefings for their operating personnel at intervals frequent enough to assure adequate understanding of the SPCC Plan for that facility. Such briefings should highlight and describe known spill events or failures, malfunctioning components, and recently developed precautionary measures.

APPENDIX

Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency.

SECTION II—DEFINITIONS

The Environmental Protection Agency and the Department of Transportation agree that for the purposes of Executive Order 11548, the term:

(1) "Non-transportation-related onshore and offshore facilities" means:

(A) Fixed onshore and offshore oil well drilling facilities including all equipment and appurtenances related thereto used in drilling operations for exploratory or development wells, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(B) Mobile onshore and offshore oil well drilling platforms, barges, trucks, or other mobile facilities including all equipment and appurtenances related thereto when such mobile facilities are fixed in position for the purpose of drilling operations for exploratory or development wells, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(C) Fixed onshore and offshore oil production structures, platforms, derricks, and rigs including all equipment and appurtenances related thereto, as well as completed wells and the wellhead separators, oil separators, and storage facilities used in the production of oil, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(D) Mobile onshore and offshore oil production facilities including all equipment and appurtenances related thereto as well as completed wells and wellhead equipment, piping from wellheads to oil separators, oil separators, and storage facilities used in the production of oil when such mobile facilities are fixed in position for the purpose of oil production operations, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(E) Oil refining facilities including all equipment and appurtenances related thereto as well as in-plant processing units, storage units, piping, drainage systems and waste treatment units used in the refining of oil, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(F) Oil storage facilities including all equipment and appurtenances related thereto as well as fixed bulk plant storage, terminal oil storage facilities, consumer storage, pumps and drainage systems used in the storage of oil, but excluding inline or breakout storage tanks needed for the continuous operation of a pipeline system and any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(G) Industrial, commercial, agricultural or public facilities which use and store oil, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(H) Waste treatment facilities including in-plant pipelines, effluent discharge lines, and storage tanks, but excluding waste treatment facilities located on vessels and terminal storage tanks and appurtenances for the reception of oily ballast water or tank washings from vessels and associated systems used for off-loading vessels.

(I) Loading racks, transfer hoses, loading arms and other equipment which are appurtenant to a nontransportation-related facility or terminal facility and which are used to transfer oil in bulk to or from highway vehicles or railroad cars.

(J) Highway vehicles and railroad cars which are used for the transport of oil exclusively within the confines of a nontransportation-related facility and which are not intended to transport oil in interstate or intrastate commerce.

(K) Pipeline systems which are used for the transport of oil exclusively within the confines of a nontransportation-related facility or terminal facility and which are not intended to transport oil in interstate or intrastate commerce, but excluding pipeline systems used to transfer oil in bulk to or from a vessel.

(2) "transportation-related onshore and offshore facilities" means:

(A) Onshore and offshore terminal facilities including transfer hoses, loading arms and other equipment and appurtenances used for the purpose of handling or transferring oil in bulk to or from a vessel as well as storage tanks and appurtenances for the reception of oily ballast water or tank washings from vessels, but excluding terminal waste treatment facilities and terminal oil storage facilities.

(B) Transfer hoses, loading arms and other equipment appurtenant to a non-transportation-related facility which is used to transfer oil in bulk to or from a vessel.

(C) Interstate and intrastate onshore and offshore pipeline systems including pumps and appurtenances related thereto as well as in-line or breakout storage tanks needed for the continuous operation of a pipeline system, and pipelines from onshore and offshore oil production facilities, but excluding onshore and offshore piping from wellheads to oil separators and pipelines which are used for the transport of oil exclusively within the confines of a nontransportation-related facility or terminal facility and which are not intended to transport oil in interstate or intrastate commerce or to transfer oil in bulk to or from a vessel.

(D) Highway vehicles and railroad cars which are used for the transport of oil in interstate or intrastate commerce and the equipment and appurtenances related thereto, and equipment used for the fueling of locomotive units, as well as the rights-of-way on which they operate. Excluded are highway vehicles and railroad cars and motive power used exclusively within the confines of a nontransportation-related facility or terminal facility and which are not intended for use in interstate or intrastate commerce.

[FR Doc.73-25448 Filed 12-10-73;8:45 am]

PART 110—DISCHARGE OF OIL

AUTHORITY: The provisions of this Part 110 issued under sec. 11(b)(3), as amended, 84 Stat. 92; 33 U.S.C. 1161.

§ 110.1 Definitions.

As used in this part, the following terms shall have the meaning indicated below:

(a) "Oil" means oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, oil mixed with ballast or bilge, and oil mixed with wastes other than dredged spoil;

(b) "Discharge" includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying or dumping;

(c) "Vessel" means every description of watercraft or other artificial contrivance used, or capable of being used, as a means of transportation on water other than a public vessel;

(d) "Public vessel" means a vessel owned or bare-boat chartered and operated by the United States, or by a State or political subdivision thereof, or by a foreign nation, except when such vessel is engaged in commerce;

(e) "United States" means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Canal Zone, Guam, American Samoa the Virgin Islands, and the Trust Territory of the Pacific Islands;

(f) "Person" includes an individual, firm, corporation, association, and a partnership;

(g) "Contiguous zone" means the entire zone established or to be established by the United States under article 24 of the Convention on the Territorial Sea and the Contiguous Zone;

(h) "Onshore facility" means any facility (including, but not limited to motor vehicles and rolling stock) of any kind located in, on, or under, any land within the United States other than submerged land;

(i) "Offshore facility" means any facility of any kind located in, on, or under, any of the navigable waters of the United States other than a vessel or public vessel;

(j) "Applicable water quality standards" means water quality standards adopted pursuant to section 10(c) of the Federal Act and State-adopted water quality standards for waters which are not interstate within the meaning of that Act.

(k) "Federal Act" means the Federal Water Pollution Control Act, as amended, 33 U.S.C. 1151, et seq.

(l) "Sheen" means an iridescent appearance on the surface of water.

(m) "Sludge" means an aggregate of oil or oil and other matter of any kind in any form other than dredged spoil having a combined specific gravity equivalent to or greater than water.

§ 110.2 Applicability.

The regulations of this part apply to the discharge of oil into or upon the navigable waters of the United States, adjoining shorelines or into or upon the waters of the contiguous zone, prohibited by section 11(b) of the Federal Act.

§ 110.3 Discharge into navigable waters harmful.

For purposes of section 11(b) of the Federal Act, discharges of such quantities of oil into or upon the navigable waters of the United States or adjoining shorelines determined to be harmful to the public health or welfare of the United States, at all times and locations and under all circumstances and conditions, except as provided in section 110.6 of this part, include discharges which:

(a) Violate applicable water quality standards, or

(b) Cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines.

§ 110.4 Discharge into contiguous zone harmful.

For purposes of section 11(b) of the Federal Act, discharges of such quantities of oil into or upon the waters of the contiguous zone determined to be harmful to the public health or welfare of the United States, at all times and locations and under all circumstances and conditions, except as provided in section 110.6 of this part, include discharges which:

(a) Violate applicable water quality standards in navigable waters of the United States, or

(b) Cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines.

§ 110.5 Discharge prohibited.

As provided in section 11(b)(2) of the Federal Act, no person shall discharge or cause or permit to be discharged into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone any oil, in harmful quantities as determined in §§ 110.3 and 110.4 of this part, except as the same may be permitted in the contiguous zone under Article IV of the International Convention for the Prevention of Pollution of the Sea by Oil, 1954, as amended.

§ 110.6 Exception for vessel engines.

For purposes of section 11(b) of the Federal Act, discharges of oil from a properly functioning vessel engine are not deemed to be harmful; but such oil accumulated in a vessel's bilges shall not be so exempt.

§ 110.7 Dispersants.

Addition of dispersants or emulsifiers to oil to be discharged which would circumvent the provisions of this part is prohibited.

§ 110.8 Demonstration projects.

Notwithstanding any other provisions of this part, the Administrator of the Environmental Protection Agency may permit the discharge of oil into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone, in connection with research, demonstration projects, or studies relating to the prevention, control, or abatement of oil pollution.

§ 110.9 Notice.

Any person in charge of any vessel or onshore or offshore facility shall, as soon as he has knowledge of any discharge of oil from such vessel or facility in violation of § 110.5 of this part, immediately notify the U.S. Coast Guard of such discharge in accordance with such procedures as the Secretary of Transportation may prescribe.

Appendix B

CODE OF FEDERAL REGULATIONS

TITLE 40 - PROTECTION OF THE ENVIRONMENT

PART 110 - DISCHARGE OF OIL

BIBLIOGRAPHY

BIBLIOGRAPHY

BULK HANDLING

Menon, P. K. 1969. Symposium on Bulk Handling of Raw Materials. Proceedings, Calcutta. xxiv, 213 p. LC Call No: TN5 .S85 1968.

COATINGS/LININGS FOR BULK STORAGE TANKS

Battelle Columbus Laboratories. Evaluation of Methods for Measuring and Controlling Hydrocarbon Emissions for Petroleum Storage Tanks. November, 1976. PB-262 789.

Naval Research Laboratory. Development of Organic Coatings for Use as Linings of Bulk Fuel Storage Tanks. 23 p. AD-A061 392/7GA.

ELECTROSTATIC IGNITION DURING LOADING/UNLOADING

Precautions Against Electrostatic Ignition During Loading of Tank Truck Motor Vehicles, Second Edition, 1975. American Petroleum Institute Bulletin 1003. This bulletin is designed to set forth precautions which should be taken to minimize the possibility of electrostatic ignition during loading of petroleum products into tank trucks. It is not intended to be a detailed specification or instruction for tank truck loading; nor is it intended to guarantee freedom from accidents.

EQUIPMENT DESIGN OF REFINERIES AND PLANTS

72-50245. Evans, Frank L. 1979. Equipment Design Handbook for Refineries and Chemical Plants. Houston, Texas. Book Division, Gulf Publishing Company, v. i, ill. LC Call No: TD690.3 .E89

79-50251. Energy Management Handbook for Petroleum Refineries, Gas Processing, and Petrochemical Plants. Houston, 1979. LC Call No: TP690.3 .E89 1979

FIRE PROTECTION IN PLANTS

72-94065. Vervalin, Charles H. 1973. Pollution Control in the Petroleum Industry. Park Ridge, N.J., Noyes Data Corporation. LC Call No. TD888.P4 J66

INPLANT PIPELINES

Oil Pipeline Measurement and Storage Practices, Vol. III, 1955. American Petroleum Institute Publication. Contains chapters on tank construction, stripping tanks, tank gaging, tank maintenance, and quantity measurement of liquid petroleum with meters.

MARINE LOADING/UNLOADING

78-620534. Alaska Department of Environmental Conservation. 1977. Tank Vessels and Marine Terminal Facilities for Oil and Liquefied Natural Gas: A Selected Bibliography. Juneau, Alaska Department of Environmental Conservation.

79-01454. Burklin, C. R. etal. Background Information on Hydrocarbon Emissions From Marine Terminal Operations. November, 1976, IV, PB-264 381

Fourth New England Coastal Zone Management Conference, 4th Annual, Durham, New Hampshire. "Perspectives on Oil Refineries and Offshore Unloading Facilities." May 13-14, 1974. Mary Louis Hunter, Editor.

048435. Kilgren, Karl H., Thomas, A. Hydrocarbon Emissions During Marine Loading of Crude Oils. 1978. Proceedings Air Pollution Control Association, 71st Annual Meeting, Houston, June, 1978.

027198. International Petroleum Times. "Loading and Discharge Marine Terminals for European Crude." 1978. Pages 15, 18, 33.

74-158901. International Oil Tanker Terminal Safety Group. 1971. International Oil Tanker and Terminal Safety Guide. London, Distributed by the Institute of Petroleum, 1971. LC Call No: VM455 .I46 1971.

058952. McGrath, P. New Concepts for Design of Very Large Storage Tanks. 1976. Design concepts are given which permit the extension of tank diameters and capabilities substantially beyond the maximum presently obtainable sizes, under the API standard 650 design rules. Proceedings American Petroleum Institute Refinery Department, Midyear Meeting, 41st, Los Angeles, May, 1976. Published by API (V55) P. 407-425.

72-178869. Savory, A. J. 1969. Conference on Tanker and Bulk Carrier Terminals. Twelfth Conference on Tanker and Bulk Carrier Tanker Terminals, November, 1969. Institution of Civil Engineers. 109 pages. LC Call No: TC365 .C65 1969.

79-00063. National Technical Information Service (NTIS). Background information on national and regional hydrocarbon emissions from marine terminal transfer operations. PB-275 484.

75-328745. Oil Companies International Marine Forum. 1974. International Oil Tanker and Terminal Safety Guide. Second revised edition. London, Applied Science Publishers, 1974. LC Call No: VM455. I46 1974.

79-309075. Oil Companies International Marine Forum, 1978. International Safety Guide for Oil Tankers and Terminals. London, Witherby, 1978. LC Call No: VM455. I45 1978.

75-328745. Oil Companies International Marine Forum, 1975. International Oil Tanker and Terminal Safety Guide. Second Edition. New York, Wiley, 1975. LC Call No: VM455 .034 1975.

New England Interstate Water Pollution Control Commission. Technical Advisory Board. 1971. Uniform Guidelines for Preventing and Control of Oil Spills, and for Oil Terminal and Vessel Handling of Petroleum and Petroleum Products. Boston, Massachusetts.

LRS78-12299. Port Safety and Tank Vessel Safety. Hearings. 95th Congress, Second Session. Washington, D.C. U.S. Government Printing Office, 1978. 571 pages.

MARITIME POLLUTION CONTROL

International Conference on Marine Pollution. London, 1973. Preparatory meeting for the International Conference on Marine Pollution, 1973 (London) International Maritime Consultative Organization. Contents: Minimization of accidental spillages of oil and other noxious substances from ships; draft resolution, international pollution of the sea and accidental spillages. GC 1080.173

Wardley-Smith, J. 1976. The Control of Oil Pollution on the Sea and Inland Waters: The Effect of Oil Spills on the Marine Environment and Methods of Dealing With Them. TD 427 .P4W375.

MONOBUOY OPERATION

77-365875. Dames & Moore. 1976. Environmental Report. Houston, Seadock, 1976. LC Call No: TD195.P4 D35

OIL PIPELINE PUMPING STATIONS

Oil Pipeline Pumping Station Operation. Vol. IV, 1956. Covers the installation, operation, and maintenance of prime movers, pumps, and auxiliary equipment found in oil pipeline pumping stations. While internal-combustion engineers and reciprocating pumps are covered, emphasis is on the electrified station with automatic controls and centrifugal pumps which characterize the postwar installations.

OVERLAND PIPELINES

Oil Pipeline Construction and Maintenance. Vol. II, Second Edition 1973. Presents chapter on capacity, design and specifications, and accident prevention. Available through API.

Recommended Practices for Liquid Petroleum Pipelines Crossing Railroads and Highways, Fifth Edition, 1980. American Petroleum Institute R.P. 1102. This recommended practice should be considered as a guide for the design, installation, inspection, and testing required to ensure safe crossings of liquid petroleum pipelines under railroads and highways. The practice applies to the construction of pipelines under existing railroads and highways and to the adjustment of existing pipelines due to the construction of new railroads and highways. Also included are nomographs for determining the circumferential stress caused by external loads in uncased carrier pipe with an internal pressure at railroad and highway crossings, as well as charts showing the recommended thicknesses for flexible casing in bored crossings.

*LRS78-21415. U.S. Bureau of Land Management. 1978. Crude Oil Transportation System. Draft environmental statement. Port Angeles, Washington to Clearbrook, Minnesota (as proposed by Northern Tier Pipeline Company). Washington, 1978. Assesses the environmental economic impact of the Northern Tier Pipeline Company's proposal to transport Alaskan oil by pipeline from a marine terminal at Port Angeles, Washington to Clearbrook, Minnesota. Discusses the possibility of oil spills, air pollutant emissions, and destruction of wildlife habitat.

PIPELINE SAFETY

LRS76-2880. American Water Works Association Journal. "Earthquake: Correlation between pipeline damage and geologic environment." 1976. Pages 165-167.

LRS79-14213. Pipeline Safety Act of 1979. Hearings, 96th Congress, First session on H.R. 2207 and H.R. 51. May 1 and June 8, 1979. Washington, U.S. Government Printing Office, 1979. 316 pages.

LRS79-9674. Pipeline Safety Act of 1979. Hearings, 96th Congress, First sessions on S. 411. Washington, U.S. Government Printing Office, 1979. 246 pages.

LRS79-4926. Pipeline Safety Act of 1979. Report to accompany S. 411. Washington, U.S. Government Printing Office, 1979. 39 pages.

LRS78-3773. Pipeline Safety--Need For a Stronger Federal Effort. 1979. Report. Washington, D.C. 19 pages.

*Library Research Service, Library of Congress, Washington, D.C.

PETROLEUM MARKETING TERMINALS

4285. A Survey of Petroleum Marketing Terminals. This report was prepared under the direction of Task Force W-19, API Environmental Affairs Department, with the assistance of its contractor, Engineering Sciences, Inc., and the cooperation of 15 member companies of the American Petroleum Institute. It presents the results of a survey of the physical and operating characteristics of 76 pertroleum marketing terminals and of the oil and grease content in their wastewater discharges.

POLLUTION CONTROL

D'Allessandro, P.L. and Cobb, C. B. 1976. "Oil Spill Control" Hydrocarbon Processing, 145-148. (March, 1976)

Department of the Navy. 1977. Oil Spill Control for Inland Waters and Harbors. Report NAVFAX P-908, Alexandria, Virginia Naval Facilities Engineering Command (January, 1977).

67-19834. Beychok, Milton R. 1967. Aqueous Wastes from Petroleum and Petrochemical Plants. London, Wiley, 1967. LC Call No: TP690.8 .B4

Department of Trade. 1974. Manual on the Avoidance of Pollution of the Sea By Oil. V. 1, 22 pages. London HMSO.

Garrett, M. J. and Smith, J. Wardley. 1976. Oil Spills from Tankers. Report of the symposium on prevention of marine pollution from ships. Acapulco, Mexico. U.S. Office of Environment and Systems, 1976. Washington, D.C. (CGWEP1-77).

Iammartino, N. R. 1976. Chemical Engineering. "Oil Spill Control Nears for Two Pesky Problems" Pages 76-80, May 10, 1976.

74-172600. Interstate Oil Compact Commission. 1966. Research Committee Subcommittee on Water Problems Associated with Oil Production in the United States. Oklahoma City, Interstate Oil Compact Commission. LC Call No: TD427.P4 I52

Joint Conference on Prevention and Control of Oil Spills. Proceedings at Washington, D.C. 1971 GC1080.C6

Joint Conference on Prevention and Control of Oil Spills. Proceedings at New York. 1969. GC1085.J6.

GC1085.L585 Little, Arthur D., Inc. 1971. Regulations, Practices, and Plans for the Prevention of Spills of Oil and Hazardous Polluting Substances. Volume I. Washington, D.C. U.S. Government Printing Office.

V393.A3055 No. CG-D-55-75. Milgram, Jerome H. 1974. Evaluation of the Strength and Safekeeping Ability of Pollution Control Barriers. J. F. O'Dea; Massachusetts Institute of Technology Washington USCG Office of Research and Development. Available through NTIS.

Oil Conference on Prevention and Control of Oil Pollution. San Francisco, 1975. National conventioneer issued at the Conference on Prevention and Control of Oil Pollution, 1975--instrumentation, equipment, and supplies exposition product ideas book. Allison Park, PA. Publishers for Conventions, Inc. 1975.

Wardley-Smith, J. The Control of Oil Pollution. 1976. London, Graham and Trotman, Ltd.

Little, Arthur D., Inc. 1974. In./Learning Systems, Guide to Water Cleanup: Materials and Methods. Cambridge, Massachusetts.

PORT AND COASTAL STRUCTURES

Johnson, C.T. Coastal Structure, 1979. Special conference on the design, construction, maintenance, and performance of port and coastal structures. Alexandria, Virginia, March 14-16, 1979. Pages 537-546.

SPILL PREVENTION: GENERAL

4283. Environmental Research Annual Status Report. Since a continuing concern of the petroleum industry is the protection and improvement of the environment, API sponsors a substantial number of scientific research projects in the environmental area. This report summarizes such projects which have recently been completed or are on-going. An API Publication.

4041. Industrial Oil Waste Control (API-ASLE Handbook). A collection of articles including "Industry's Oil Waste Problem," "Standards for Effective Oil Waste Control," "Control of Oil Waste at the Source," "Oily Wastewater Treatment," and "Disposal of Oily Wastes."

International Conference on Tanker Safety and Pollution Prevention. London, 1978. Tanker safety and pollution prevention, 1978: Final act of the conference with attachments, including the protocol of 1978 relating to the International Convention for the safety of life at sea, 1974 and the protocol of 1978 relating to the International Convention for the Prevention of Pollution from Ships, 1973. London: Intergovernmental Maritime Consultative Organization. VK 200.1775 1978.

Joint Conference on Prevention and Control of Oil Spills. New York, 1969. Proceedings. American Petroleum Institute. GC 1080 .J64 1969.

Joint Conference on Prevention and Control of Oil Spills. Washington, D.C. 1971. Proceedings. American Petroleum Institute. GC 1080 .J64 1971

Joint Conference on Prevention and Control of Oil Spills. Washington, D.C. 1973. Proceedings. American Petroleum Institute. GC 1080 .J64 1973.

Environmental Protection Agency. Oil Pollution of Rivers and Harbors. Book Catalog V. II, 1974.

72-75239. Jones, H. R. 1973. Pollution Control in the Petroleum Industry. Park Ridge, NJ, Noyes Data Corporation. LC Call No. TD888.P4 J66.

Little, Arthur D. Inc., 1971. The Prevention of Spills of Oils and Chemicals into Baltimore Harbor and Environment. Report to Maryland Environmental Service. Cambridge, Massachusetts. GC 1211 .L58.

Milgram, J. 1977. (Sea Grant Program-MIT.) Being Prepared for Future Argo Merchants. Rockville, MD, National Oceanic and Atmospheric Administration. (April, 1977.)

Oil Spill Prevention Institute. 1978. Test and Research Facilities of the Oil Spill Prevention Institute. The Oil Spill Prevention Institute, The Shipbuilding Research Center of Japan.

4225. Oil Spill Prevention Primer. This booklet outlines in a general way procedures designed to reduce the risks of an oil spill. It deals with controls which may be found in most industry operations. API Publication.

4271. Oil Spill Control Course (December 1975). The purpose of this course is to provide the trainee with information and training necessary for handling an oil spill within the capabilities of manpower and equipment at a company facility. API Course.

Oil Spill Conference. New Orleans, 1977. Sponsored by American Petroleum Institute. "Prevention, Behavior, Control and Cleanup."

Oil Spill Liability and Compensation. Hearings from 95th Congress, Committee on Commerce, Science, and Transportation. 1977. June, 1977. Washington, U.S. Government Printing Office. 346 p. LRS 77-11270.

National Petroleum News. January, 1980. "Brooklyn Spill: 17 Million Gallons Under the Sidewalks of New York," Pages 34,35, 58 and 59.

72-171291. Presentation for the Inquiry into Pollution Control of Petroleum Refineries in British Columiba, Vancouver, BC. 1972. LC Call No: TD899. P4 P73.

Potter, Jeffrey. 1973. "Disaster by Oil. Oil Spills: Why They Happen, What They Do, How We Can End Them." GC1085 .P67

Sittig, Marshall. Oil Spill Prevention and Removal Handbook. 1974. Noyes Data Corporation, Park Ridge, NJ.

Sittig, Marshall. 1978. Petroleum Transportation and Production: Oil Spill and Pollution Control. Noyes Data Corporation. Park Ridge, NJ.

Smith, Wardley, J. 1979. The Prevention of Oil Pollution. John Wiley and Sons, New York. TD .P4P83.

Voluntary Environmental Activities of Large Chemical Companies to Address and Control Industrial Chemicals. US/EPA. PB-271 907/8BE.

74-179973. Institute of Petroleum, London. 1971. Gas Evaluation--Tanker and Terminal Safety. LC Call No: VM455 G.37.

Trentacoste, Nicholas P. 1980. Spill Prevention, Control and Countermeasure Practices at Small Petroleum Facilities. NTIS TD 427 .P4T84.

STORAGE TANK SEEPAGE

European Model Code of Safe Practice For the Prevention of Ground and Surface Water Pollution by Oil From Storage Tanks and During the Transport of Oil. London: Applied Science Publishers. 1974. TP 692.5 .E95. Prepared by a working group formed following a meeting of representatives of European technical organizations held at the Institute of Petroleum, London.

TANK BOTTOM FAILURES

063507. Edwards, H. R., Diesterte, R. J. Petroleum Engineer May, 1979. "How Reinforced Plastic Lining Repairs Petroleum Storage Tanks. This article discusses some of the reasons for tank bottom failure, gives case history examples, and provides detailed procedures for coating steel bottoms with fiberglass reinforced plastics. Volume 51, n. 6. pages 112-126.

Card, J. C. 1975. Marine Technology. "Effectiveness of Double Bottoms in Preventing Oil Outflow from Tanker Bottom Damage Incidents." Pages 60-64,

RP 1004. Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles, Fourth Edition, 1977 (Supersedes Third Edition, 1975.) The objective of this recommended practice is to provide an industry standard for bottom loading and vapor recovery of proprietary and hired carrier DOT MC-306 tank vehicles at terminals operated by more than one supplier. It is intended to guide the manufacturer and operator of a tank vehicle as to the uniform features that should be provided to permit loading of a tank vehicle with a standard 4-in. adapter.

TANK DESIGN

78-903839. Indian Standard Institution. 1977. Indian Standard Code of Practice for Design, Fabrication, and Erection of Vertical Mild Steel Cylindrical Welded Oil Storage Tanks. First Revision. New Delhi, India. LC Call No: TP692.5 I.52

TANK FOUNDATIONS

058959. Penman, A. 1977. Soil Structure Interaction and Deformation Problems with Large Oil Tanks. International Symposium on Soil Structure Interaction. University of Ruorkee, India Pages 521-536.

TRANSPORTATION OF HAZARDOUS MATERIALS

European Model Code of Safe Practice For The Prevention of Ground and Surface Water Pollution By Oil From Storage Tanks and During the Transport of Oil. London: Applied Science Publishers. 1974. TP 692.5 .E95. Prepared by a working group formed following a meeting of representatives of European technical organizations held at the Institute of Petroleum, London.

Fawcett, Howard H., Wood, Wm. S. 1979. Toxic Chemicals and Explosives Facilities (Handling and Transport of Hazardous Materials). ACS Symposium, Series 96, p. 263-272. 79-03738.

Great Lakes Basin Committee. October 18-19, 1978. Transportation of Hazardous Materials in the Great Lakes Region: Recommendations for the Future. Great Lakes Basin Committee; Standing Committee on Transportation, etal. Seminar proceedings. 79-04063.

LRS79-3517. Hazardous Materials Transportation. A review and analysis of the Department of Transportation's regulatory program. Prepared for the Committee on Commerce, Science and Transportation. U.S. Senate. Washington, U.S. Government Printing Office, 1979. 251 pages.

LRS79-4856. Hazardous Materials Transportation Act Amendments. Report to accompany H.R. 3502 Including cost estimate of the Congressional Budget Office. Washington U.S. Government Printing Office, 1979. 12 pages.

LRS76-14380. Hazardous Materials Transportation Act. 1976. Hearing 94th Congress, Second session on S. 2991. March 4, 1976. Washington, U.S. Government Printing Office, 1976. 139 pages.

LRS76-8176. Hazardous Materials Transportation Act Extension. 1976. Joint hearing before the Subcommittee on Surface Transportation and the Subcommittee on Aviation of the Committee on Public Works and Transportation, House of Representatives 94th Congress, Second session on H.R. 13124. May 10, 1976. Washington, U.S. Government Printing Office. 33 pages.

089892. Hirota, Yoshiro. 1978. Japan Railway Engineer. "Safety Measures for Transportation of Hazardous Materials." Volume 18, N. 2, pages 20-21.

LRS77-21721. National Technical Information Service (NTIS) 1974. A Model Economic and Safety Analysis of the Transportation of Hazardous Substances in Bulk. Final Report. Washington, U.S. Maritime Administration, Office of Domestic Shipping. 266 pages.

LRS79-4562. Rail Transport of Hazardous Material. Hearing, 95th Congress, Second Session, March 20, 1978, Part 1. Washington, U.S. Government Printing Office, 1979. 158 pages.

RP 500C. Recommended Practice for Classification of Areas for Electrical Installation at Petroleum and Gas Pipeline Transportation Facilities, 1966. (Reaffirmed, 1974) This recommended practice classifies areas within petroleum and gas pipeline transportation facilities for the installation of electrical equipment. Classified areas include pump stations, compressor stations, storage facilities, loading racks, and manifold and pipeline right-of-way areas where flammable liquids and gases are handled. The classifications contained herein were developed with consideration being given to a uniform system for pipelines which, by their very nature, are subject to various degrees of public exposure. Consideration also was given to the increasing application of centralized control with the consequent increase in unmanned or semiattended facilities. It includes statements and recommendations for classification of areas based on experience of the pipeline industry. It does not constitute, and should not be construed as a code of rules or regulations.

RF 1111. Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines, First Edition, 1976. This recommended practice sets forth criteria for the design, construction, testing, operation and maintenance of offshore hydrocarbon pipelines. These criteria cover engineering considerations for the movement by pipeline of substances commonly encountered in hydrocarbon production and transportation operations. It is intended for application in all climatic regions. The design, construction, inspection and testing provisions of this recommended practice are not intended to be applied to offshore hydrocarbon pipeline systems designed or installed before its issuance. The operation and maintenance provisions of this recommended practice are generally suitable for application to existing facilities, as soon as such application is practicable. This recommended practice does not apply to production facilities or to risers and piping installed on production facility platforms. Neither does it cover the transportation of cryogenic substances or large storage facilieies, tanker loading arms, monobuoy piping, swivel fittings, flexible hoses and related equipment. API Publication.

LRS78-15042. Transportation Law Journal, Volume 19, No. 1, 1978. "Recent Developments in the Transportation of Hazardous Materials." Pages 97-120.

PB-276 734/1Gl. United States Environmental Protection Agency. Manual for the Control of Hazardous Material Spills. Volume 1: Spill Assessment and Water Treatment Techniques.

TANKER SAFETY

Large Tankers--Our Energy Lifelines, 1979. This 24-page brochure describes Very Large Crude Carriers (VLCC), their structure use, and general operation. The booklet also contains information on pollution prevention, crew training, tanker safety, tanker regulations and deepwater ports. API Transportation Department.

VAPOR CONTROL

75-304166. American Petroleum Institute. Symposium on Evaporation Loss of Petroleum From Storage Tanks, Chicago, 1952. LC Call No: TP692.5 .S9 1954. Subjects include oil storage tanks and evaporation control.

Bulletin 2522. Comparative Test Methods for Evaluating Conservation Mechanisms for Evaporation Loss, 1967. This bulletin presents relatively simple test procedures that have practical application in the determination of evaporation loss. These procedures may be used when the precise measurements necessary for a complete and accurate evaluation of evaporation loss provided by the comprehensive test methods of API Bulletin 2512 are not available or applicable. API Publication.

Bulletin 2518. Evaporation Loss from Fixed-Roof Tanks, 1962. This bulletin contains the correlation and evaluation of test data from companies concerned with evaporation loss from fixed-roof tanks. The information has been used to develop methods of estimating breathing and working losses from gasoline and crude oil tanks. Also included is a loss calculation summary and sample calculations. API Publication.

Bulletin 2517. Evaporation Loss from Floating-Roof Tanks, 1962. A method for estimating standing-storage and withdrawal evaporation losses from floating-roof tanks is presented along with a description of metallic and nonmetallic floating-roof seals. API Publication.

Bulletin 2516. Evaporation Loss from Low-Pressure Tanks, 1962. Breathing, working and leakage losses encountered in low-pressure tanks (atmospheric to 15 psig) are discussed in this bulletin, which also provides equations for calculating these values. API Publication.

Bulletin 2514. Evaporation Loss From Tank Cars, Tank Trucks, and Marine Vessels. Testing methods and correlations for loading, unloading and transit losses from tank cars, tank trucks, and marine vessels are explained. API Publication.

Bulletin 2513. Evaporation Loss in the Petroleum Industry--Causes and Control, 1959. (Reaffirmed 1973). Sources of evaporation loss, the factors affecting evaporation and the equipment and procedures for controlling evaporation loss are discussed. API Publication.

Bulletin 2512. Measuring Evaporation Loss from Petroleum Tanks and Transportation of Equipment, 1957. In this first of a series of bulletins that the Committee on Evaporation Loss Measurement has issued on the subject, technical details are given for several methods of measuring actual evaporation losses. API Publication.

Evaluation of Hydrocarbon Emissions from Petroleum Liquid Storage. US/EPA PB-286. 190/4BE.

Bulletin 2514A. Hydrocarbon Emissions from Marine Vessel Loading of Gasolines. 1960. This bulletin presents information on hydrocarbon emissions that occur during the loading of gasoline into marine vessels. The data were obtained during the loading of 71 ship compartments and 12 barge compartments. API Publication.

Bulletin 2523. Petrochemical Evaporation Loss from Storage Tanks, 1969. This bulletin presents procedures utilizing the test results and correlations for gasoline evaporation loss give in API Bulletin 2518 and provides a method for determining the evaporation loss of petrochemicals. Also, included are a basis for the new correlation and a sample calculation to demonstrate the method presented. API Publication.

Bulletin 2519. Use of Internal Floating Covers and Covered Floating Roof to Reduce Evaporation Loss, 1976. This bulletin describes methods to reduce evaporation from a free liquid surface in a fixed-roof tank by separating the liquid and vapor regions and summarizes the characteristics of floating covers and steel pans. API Pulbication.

Bulletin 2515. Use of Plastic Foam to Reduce Evaporation Loss, 1961. Evaluation of effectiveness, testing methods for measuring loss, loss reduction in static and working service, disappearance of foam particles and reduction in corrosion rates are covered. API Publication.

Bulletin 2521. Use of Pressure-Vacuum Vent Valves for Atmospheric Pressure Tanks to Reduce Evaporation Loss, 1966. This bulletin describes the use of pressure-vacuum vent valves to reduce evaporation loss of petroleum and petroleum products stored at essentially atmospheric pressure in above ground fixed-roof tanks and variable-vapor-space systems. It also presents factors to be considered when selecting vent valves and serves to increase the awareness of operationals and maintenance requirements. API Publication.

Bulletin 2520. Use of Variable-Vapor-Space Systems to Reduce Evaporation Loss, 1964. This bulletin describes the various types of variable-vapor-space systems used for storing gasolines and presents methods for determining the expansion volume required when economic studies indicate such a system is justified.

UNDERGROUND STORAGE

LRS77-18494. Mining Magazine. "Storing Oil in Rock Caverns." Volume 137, November, 1977, p. 541.

HYDROCARBON EMISSIONS FROM TANKS

058954. Harrier, Robert D. Hydrocarbon Emissions from Fixed-Roof Tanks. API, Pacific Coast Chapter Meeting, Bakersfield, October 25-27, 1977. 14 pages.

PETROLEUM MARKETING TERMINALS

4285. A Survey of Petroleum Marketing Terminals. This report was prepared under the direction of Task Force W-19, API Environmental Affairs Department, with the assistance of its contractor, Engineering Sciences, Inc., and the cooperation of 15 member companies of the American Petroleum Institute. It presents the results of a survey of the physical and operating characteristics of 76 petroleum marketing terminals and of the oil and grease content in their wastewater discharges.

PNL-3613
UC-11

DISTRIBUTION

No. of
Copies

OFFSITE

A. A. Churm
DOE Patent Division
9800 S. Cass Avenue
Argonne, IL 60439

John Cece
Environmental Control Division
Department of Energy
Washington, D. C. 20545

224 DOE Technical Information Center

3 U. S. Environmental Protection Agency
Waterside Mall
Washington, D. C.

Ken Biglane
Russ Wyer
H. Van Cleave

Dr. T. G. Johns
Battelle
Houston Operations
2223 West Loop South, Suite 320
Houston, TX 77027

10 J. L. Goodier
Battelle
Washington Operations
2030 M Street, N.W.
Washington, D. C. 20036

R. J. Siclari
Battelle
Washington Operations
2030 M Street, N.W.
Washington, D. C. 20036

ONSITE

DOE Richland Operations Office

H. E. Ranson

9 Pacific Northwest Laboratory

D. B. Cearlock
G. W. Dawson
Publishing Coordination (2)
Technical Information (5)