EPA/450/3-78/016

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EMISSION CONTROL TECHNOLOGY FOR TWO MODEL MARINE TERMINALS HANDLING CRUDE OIL AND GASOLINE

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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by

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Contract No. 68-02-2838

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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
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Publication No. EPA-450/3-78-016

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1.0 INTRODUCTION

The purpose of this study is to develop basic background information on emission control systems for a hypothetical deep water marine terminal handling crude oil, and an inland marine terminal handling crude oil and gasoline. Terminal models represent maximum design cases as though for new installations, in order to verify physical feasibilities with commercially available technology, and therefore are not "typical" marine terminals as might exist today. These hypothetical terminals do not provide a suitable basis for retrofit consideration in existing terminals.

The study includes a comparative cost analysis for alternative emission control systems together with comparable safety and reliability analysis for both marine terminal modules. A wide variety of collection systems has been considered. Seven alternative systems were ultimately selected as being the most comparable and/or feasible for the two marine terminal facilities. Each emission control system for marine vessel and shore tankage at both hypothetical terminals has been compared to a base case arrangement having no emission controls for marine vessels and having external (open top) floating roof storage tanks on shore.

The collection and disposal of hydrocarbon emissions from marine vessels at berth and shore tankage has been considered both separately and in combined displacement systems. Natural gas, nitrogen, and flue gas have been evaluated as "blanketing" media. Facility design and cost analysis has been developed for relative cost effectiveness in the limited time available for this analysis. Systems have been process-developed and equipment-rated with redundancy for reliability. Major pipelines have been sized, terminal layouts established, vendors have been contacted for current pricing, related utilities and manpower costs established, load factors have been developed for direct operating costs, and secondary hydrocarbon emissions have been estimated along with total control methods to enhance safety.

The use of fixed roof tankage with any vapor recovery system in lieu of external floating roof (open top) tankage is a sacrifice of safety, and represents additional capital investment, and increased operating expenses, for the sake of reducing hydrocarbon emissions. Consequently, developments and conclusions established by this report are intended to compare these burdens on private industry in dollars per ton of hydrocarbons reduced, and to qualify related safety aspects, for various methods of emission control. Adsorption, absorption and catalytic conversion methods of vapor control are beyond the scope of this study.

2.0 SUMMARY

Seven vapor control system cases have been selected for comparing cost versus hydrocarbon emission reduction against two maximum sized base case marine terminal models, both having a set of fixed conditions. Emissions other than hydrocarbons to atmosphere are not germane to the emission control economics of this study, however, other atmospheric pollutants, including marine stack emissions, have also been developed. Neither liquid nor solid wastes occur in definable quantities.

Each vapor control system for tankage is sacrificing safety, by virtue of the complexity involved, for the sake of reducing hydrocarbon emissions beyond that obtainable by passive external floating roof tank seals. Floating roof tanks are intrinsically safer than vapor control systems because their vapor spaces are negligible. Furthermore, each such system contains an enclosed gas volume which provides a potential source of atmospheric emissions that can invalidate the purpose of the total vapor recovery system by any one of several possible mal-operations.

Facility No. 1 is a deep water terminal servicing 125,000 dead weight ton oil tankers which discharge 2,250,000 B/CD of crude oil, which does not require heating for fluid properties. Facility No. 2 is a shallower inland port servicing 35,000 dead weight ton oil tankers which discharge 525,000 B/CD of the same crude oil and 175,000 B/CD of gasoline. Both terminals discharge their commodities to pipelines except that Facility No. 2 also discharges some gasoline into unballasted dedicated barges. Ships are ballasted at berth to 20% of their cargo capacity in unsegregated compartments. Base case conditions are without vapor control on ships or barges, and terminal storage is exclusively with open top, external floating roof tankage.

Base case hydrocarbon emissions have been computed from Supplement 7 of AP-42 "Compilation of Air Pollutant Emission Factors" 2nd Edition.[1] With these factors three quarters of the base case hydrocarbon emissions from Facility No. 1 and more than three-quarters from Facility No. 2 result from ship ballasting and barge loading operations, and essentially all of the rest come from floating roof tank seals. Both external and internal floating roof seal factors assume a value of 1.0 in the conventional API vapor loss formulas. There is substantial evidence, however, that this factor is inordinately high.[2] To illustrate the sensitivity of this feature, total hydrocarbon emissions are reduced about 21% in Facility No. 1 and 8% in Facility No. 2 with a seal factor of 0.1. The only relative distinction between emissions from internal and external floating roof tankage is that a 4 mph wind is assumed in the internal floating roof, while both terminal conditions assume ambient wind to average 6 mph for the external configurations.

Vapor control systems which have been evaluated for both facilities can be summarized using the following abbreviations:

XFR = external (open top) floating roof tanks

IFR = internal floating roof tanks

CR = cone roof tanks

R = refrigeration

I = incineration or flare

C = compression

NG = natural gas

Case	Marine Emission Control	Tankage Emission Control	Blanket Media
Base	none	XFR	-
I	R	XFR	-
I A	R	IFR	none
II	I	CR + I	NG
II A	I	IFR + I	NG
III	R	CR + R + I	NG
III A	R	IFR + I	NG
IV	R	CR + C	NG (w/returns)
IV A	R	IFR + C	NG (w/returns)
V	R (combined)	CR + C	NG (w/returns)
V A	R (combined)	IFR + C	NG (w/returns)
VI	R	CR + R + I	nitrogen
VI A	R	IFR + I	nitrogen
VII	R (combined)	CR + R	flue gas
VII A	R (combined)	IFR + R	flue gas

The word "returns" is meant to mean natural gas returns to the gas utility supply system, and the word "combined" to mean that marine and tankage emission control is with balanced displacements between marine vessels at berth and shore tankage. In these Cases V and VII, fixed tank roofs are 1/2" thick, instead of 3/16", to allow more operating pressure margin, and terminal staffs are increased to coordinate ship and shore activities. Another 1/8" corrosion allowance is provided to all interior surfaces in Case VII that are exposed to cold flue gas. Case VII receives flue gas primarily from ships' stacks at berth.

Cases IV, V, VI and VII have gas holders that receive and recycle blanket gas. Holder capacities vary up to about 25% of total terminal tankage volumes.

In all but Case I, tankage is blanketed with a gas media, and marine vessels are also blanketed with the same media in Cases V and VII. Hydrocarbon vapors will become saturated in these enclosed blanket medias, and the referenced emission factors, which are intended for vapor losses into unsaturated air movements, are not applicable to this enclosed environment. Net effluent gases from enclosed blanket systems are assumed herein to be saturated with hydrocarbons.

Design capacities for equipment in each vapor recovery case have been process-rated for the most extenuating set of circumstances consistent with a selected schedule of liquid transfers at each terminal. These capacities conservatively include breathing volumes as defined by AP-42, although such volumes would be much less by that amount which is not vaporized into saturated gas blankets. Schedules have been selected to reflect each coincident occurance possible with the average daily terminal thru-puts required of each facility. This operating approach is considered more objective than employing a random arrangement of operation histograms. Four days of varying occurances resulted from these scenarios, and each day was calculated for net expulsions and impulsions, including breathing inhalations and exhalations during the night and day hours, respectively, for cone roof tankage. Ships' ballasting has been assumed to occur during ship unloading operations. A complete scenario of ship and tug-boat movements has also been developed for both terminals.

The size of floating roof blanket gas holders has been based on the blanketing capacity needed to supply 1 1/2 days of maximum pump-out replacements. Flexible diaphram gas holders have been sized to store at lease one hour of maximum total tankage expulsion rates. Inert gas generators have been sized to reduce the oxygen concentration in one empty storage tank from 21% to 4% in about 48 hours, and while producing an inert gas containing 1% oxygen. This purging is necessary for safe start-up operations after tank turn-arounds. The number of units of equipment to service a process function have been selected to conform to commercially available sizes, and to provide adequate redundancy so that one unit can be shut down for maintenance without shutting down the total vapor control system. Exceptions to this redundancy occur in large, expensive refrigeration units and in facilities requiring little if any maintenance, such as ground level flares and flame arrestors. Small rotating machinery has been spared with two 100% units and larger machines with three 50% units. Control systems for each vapor recovery case have been defined in a manner which optimizes safety aspects with the best available technology.

Total installed costs reflect the difference between base case facilities and each vapor recovery system case selected. Total system costs have been derived by summarizing individual modulated equipment function costs. Fourth quarter 1977 and first quarter 1978 costs have been obtained for equipment and materials delivered to the Los Angeles area. Equipment modules include estimated equipment erection costs and all associated piping, instrumentation, electrical, structural, civil, painting, insulation, start-up, engineering pro-rate, construction indirects, spare parts and expendable costs, in addition to the delivered equipment cost. Vapor collection and blanket gas distribution piping have been treated as separate modules to illustrate the cost magnitude of these features. Direct operating costs are also modulated with equipment. In this case, design utility loads, associated operating and maintenance labor, and associated secondary emissions, are reduced by a load factor obtained from the aforementioned schedule of liquid transfers at each terminal. Direct operating costs are further divided into high and low gas and electric utility rates, consistant with current maximum and minimum rates in coastal regions of the United States. Thus, any equipment module can be extracted from or added to a total facility cost difference.

Cost effectiveness of each vapor control case has been evaluated from the ratio of the annualized costs of the system to the net reduction of hydrocarbon emissions obtained by the system. Total installed costs have been annualized by a return of capital constant which reflects interest, taxes, and depreciation on the cost of each installed system. Cost effective values are somewhat insensitive to the removal of the last vestiges of contaminents because of the relative cost of capital investments to that of the difference in hydrocarbons removed.

3.0 CONCLUSIONS

Vapor control facilities have been sized on the basis that net effluent gases from each vapor control system can be handled at peak tanker unloadings while no commodities are being transfered from the terminal, and that blanket gas supplies can be provided at peak terminal discharges while no tankers are being unloaded. Internal vapor control piping (or ducting) has been sized for maximum vapor expulsions and impulsions from any one or more shore tanks and/or marine vessels. Duct sizes have been calculated for safe operating pressure margins below tank relief value settings. The resulting size of vapor collection and distribution headers in these large, atypical terminals consequently vary up to 80" in diameter, and are supported overhead for appropriate drainage. Multiple equipment units are employed where design capacities exceed that for commercially proven equipment sizes. However, the magnitude of these total system applications exceeds any known real world installation, and their feasibilities in this context therefore, have not been proven commercially.

The cost of any vapor recovery system of the magnitude considered in this study gives cause to consider the relative cost effectiveness of other methods of mitigating hydrocarbon emissions. Requiring all oil tankers to have total segregated ballast, for instance, would in itself reduce total terminal hydrocarbon emissions from the deepwater port facility in this study by 75%. The verification and monitoring of realistic double seal floating roof factors could conceivably reduce total estimated terminal hydrocarbon emissions in this study by another 20%, considering an ideal seal factor of 0.1. These two developments alone, therefore, would collectively reduce calculated emissions by some 95%. A vapor control system for the remaining 5% would increase the cost per ton of hydrocarbons removed by more than 20-fold.

Discounting the benefits of segregated ballasts, and allowing a 1.0 seal factor for floating roof double seals, Case I has been shown to be the most cost effective arrangement. Here ballast and barge emissions only are refrigerated and tankage remains with external floating roofs. Since hydrocarbon emissions from marine vessel loading and unloading operations comprise 75% of all such emissions from Facility No. 1 and 89% of those from Facility No. 2, investments to reduce these emissions would obviously be most cost effective. Conversely, investments for tankage vapor control systems become relatively less cost effective, especially in those systems where large blanket gas storages are used. Furthermore, since these massive volumes of blanket gas are saturated with hydrocarbon vapors, there prevails the potential ability for such systems to defeat their purpose by leaking these gases into the atmosphere through maloperation from time to time.

The cost effectiveness of Case IA is the next best evaluated. This case also refrigerates ballast and barge emissions, but in addition uses air-vented internal floating roof tankage instead of external floating roof tankage. Installed costs are significantly more than Case I because of internal versus external floating roofs. Although tankage emissions are passively restrained by both Case I and IA, the latter case presents the need to maintain a very lean gas mixture in the enclosed tank ullages. Explosive ranges begin under 98 vol % air. Being a passive system, natural air movement is needed in these ullages which, in itself, stimulates seal leakage.

Cases II and IIA waste natural gas-blanketed tank emissions and marine vessel emissions to flare, a feature which makes Case IIA, with internal floating roofs, the next most cost effective control system. Case II, with cone roof tanks, on the other hand, becomes the least cost effective case because of the hydrocarbon vapor from free liquid surfaces that is wasted to flare. This case illustrates that emissions from cone roof tanks can be reduced almost 99% by the use of more expensive internal floating roof tanks, Case III therefore compares the value of recovering these marine and cone roof tankage emissions by refrigeration before incineration. Thus, the high utility rate example for both terminals in Case III converts the least cost effective vapor control system (Case II) to an average cost effective system, and the low utility rate example converts Case II to one of the better cost effective systems, by refrigerating cone roof tank emissions.

Cases IV, V, VI and VII (and their alternates), are much more cost intensive, primarily because of their ability to store and recycle blanket gas. Capacities are provided to supply terminal pipeline pumpouts in the absence of tanker unloadings for 1 1/2 days. Blanket gas make-up and disposal means are not necessary with blanket storage capacities equal to total terminal volumes. These case studies have blanket gas storages under 25% of total terminal volumes in order to reduce capital costs with reasonable inventory management. Cases IV and VI blanket tankage with natural gas and nitrogen, respectively, while V and VII, which totally recover all hydrocarbon emissions by combining marine vessel emissions at berth with shore tankage in balanced displacement system, use a natural gas and flue gas blankets respectively. These two cases are expensive primarily because of additional tank roof thicknesses that are used for improving the safety of the operations. The most cost effective control system of these recycled blanket gas cases is Case V and the next is IV, both having cone roof tankage and natural gas blankets. Their alternate cases with internal floating roof tanks are substantially less cost effective because tank emissions restrained by internal floating roofs are not an important feature with these totally enclosed and saturated vapor recovery systems. Treating units are included in Cases IV and V to return excess blanket natural gas to commercial pipeline service, the recovery of hydrocarbons being incidental. Case V, which balances a natural gas blanket between marine vessels and shore tankage, requires tankers and barges to be natural gas blanketed. The economics of Cases IV and V, consequently, are dependent upon the value of net excess blanket gas as a fuel elsewhere, and Case V further depends upon the acceptance of marine vessels containing cargo ullages of natural gas. A Btu import/export ratio of about 1100 to 1 would result at each crude receiving terminal in Case V. Case VII, which is like Case V, but utilizes flue gas as an inerting media instead of natural gas, is the lease cost effective control system evaluated. Although tankers are being inerted with flue gas, the cost of their supplying their stack gas to a terminal for blanket gas usage instead of to their cargo compartments has been found in this study to be very cost intensive. Costs are attributed not only to increased tank roof thicknesses for operating safety, but for an additional 1/8" corrosion allowance on all steel surfaces exposed to the flue gas. Adding further to the costs of Cases V and VII is the need for additional manpower to coordinate marine and terminal operations safely.

While cost effectiveness is an objective measurement for the cost of removing hydrocarbon emissions from the atmosphere, more subjective considerations also warrant concern. The margin of operating safety should perhaps head the list. The potential impact of human error and of faulty equipment operations, the consequence of tank fires, the reliability of automatic control equipment, and the ease of operating and maintaining vapor control systems can easily overweigh marginal cost effectiveness differences. Additional fire control investments have been added to each of these cases utilizing cone roof tanks. It has been noted that internal floating roof tanks of the sizes in the two terminal facilities studied may have difficulty retaining reliable floating roof performance. Control instrumentation has been defined and estimated with the intent of automatically purging blanket gas mixtures when preselected unsafe oxygen levels are recorded by oxygen analyzing monitors in strategic blanket gas locations. Additional staffing has been added for complicated operations. Installation and operating designs have been estimated that treat vapor control systems in each case as an auxiliary device which must be as reliable and safe as the best technology can afford because the primary purpose and human attention in any terminal facility is in the transfer of bulk hydrocarbons, and not in the operation of a vapor control system.

It has been noted that emission control effectiveness and cost effectiveness are not necessarily compatible in view of the gas and electric energy consumed for the Btu value recovered. Similarily, it has been noted that all vapor control systems represent a compromise with ultimate terminal safety for the sake of recovering hydrocarbons.

4.0 BASE CASE

Base case conditions have been established for two marine terminal models in order to compare the relative costs and emission reductions affected by each vapor control system at each terminal. Refinery operations are not associated with either terminal operation. Terminal sizes and throughputs are maximum in order to maximize the utility of commercially available technology in controlling emissions. No attempt has been made to establish a United States average set of crude oil and gasoline properties, tanker configurations, or marine procedures. The wide variations in the current world tanker fleet and in U.S. terminal operations would lend no credence to an "average" terminal module in any case. These features are believed to be reasonable for such large terminal facilities, however, and satisfactory to compare the effectiveness of alternative vapor control systems.

Facility No. 1 is a deepwater terminal which receives 2,250,000 B/CD of crude oil by tanker and dispatches it to pipeline. Facility No. 2 is an inland port terminal which receives 525,000 B/CD of crude oil and 175,000 B/CD of gasoline, by tankers, and dispatches all of it to pipeline except 5,000 B/CD of gasoline, which is removed by barge.

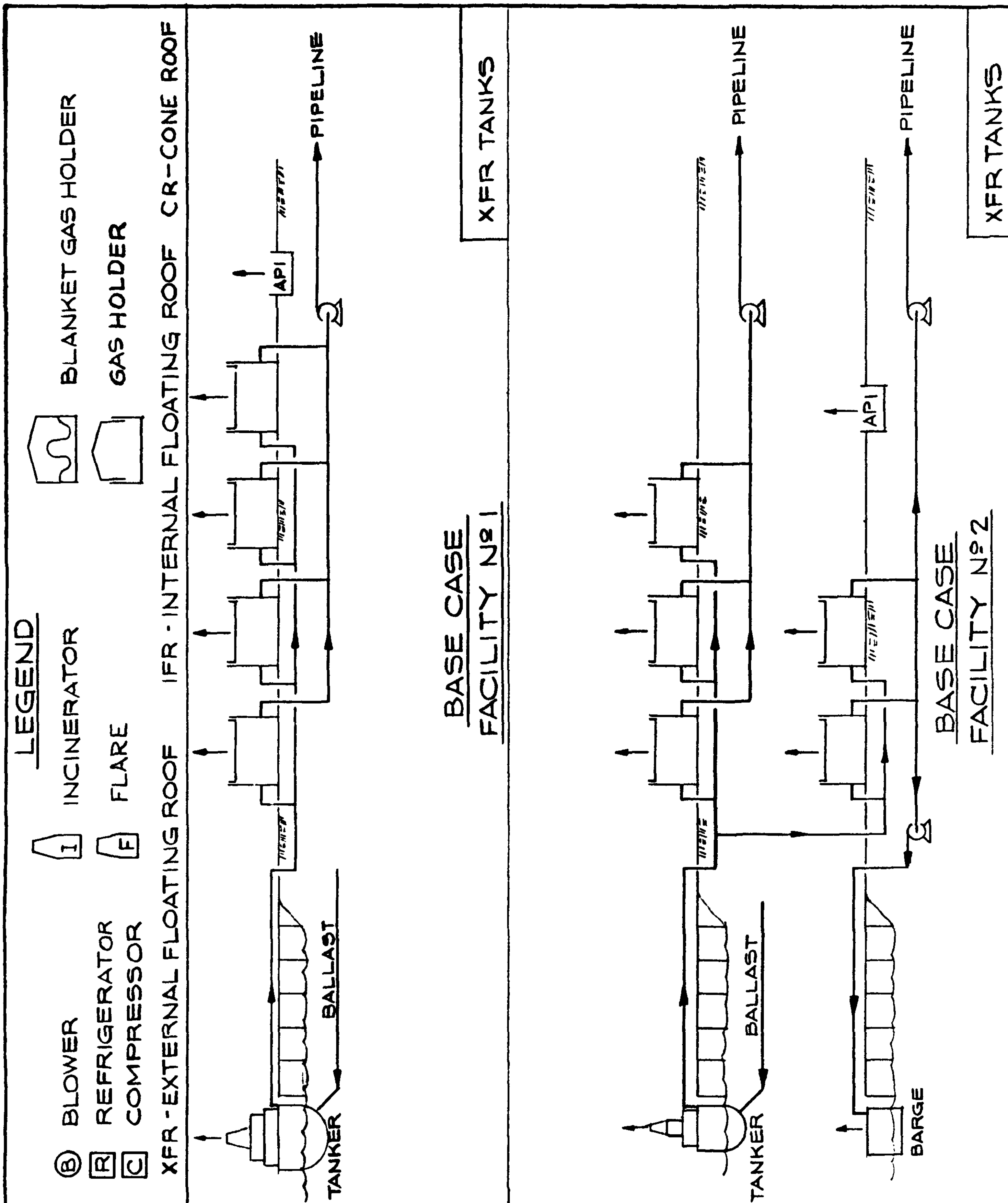
Vapor control system cost and emission removals require the definitions of these two facilities, which are outlined below.

4.1 GENERAL

Both models are considered essentially sea level terminals with ship and barge berthing facilities at docks which run to shore-side tankage. Ship and barge unloading pumps, therefore, discharge directly into tankage without the aid of intermediate booster pumps. Ships are ballasted at berth to 20% of their cargo capacity in unsegregated compartments. Neither tankers nor barges are necessarily inerted. Outgoing crude oil and gasoline from both terminals are pumped into pipelines at high pressures. Gasoline is also barged out from Facility No. 2 in dedicated, unballasted barges. Ballast water treating, therefore, is not normally necessary. However, standby water treating facilities are provided in both models, but emissions therefrom are not counted. Annual average diurnal temperature change is 18°F and wind velocity averages 6 mph at both terminals. Crude oil is 34.5° API with an RVP of 6.0 psia. Average annual storage and transportation temperatures are 75°F. Crude oil heating is not necessary. Vapor from crude oil contains essentially no H_2S, however, the effect of H_2S on vapor recovery systems has been addressed. Average tank outage is considered to be 50% at both terminals. Tanks are of welded construction and exterior surfaces are painted white. The sides of the tanks are clean white and the roofs a dirty white.

Both terminal facilities are without steam generation capability, since crude oil heating is not necessary, and electric power and natural gas is available in the quantities needed for the various vapor control systems. Firewater is assumed to be provided from sea water at both facilities and major fires require manpower from local fire districts.

A simplified base case emission flow diagram is shown for both facilities on Drawing 153-1-5. This diagram is used to overlay various vapor control systems.



ISSUE	NO	DATE	REVISION	BY	CK	APPVD	ISSUE	NO	DATE	REVISION	BY	CK	APPVD

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract #68-02-2838	153-1-5	0
	LOCATION	Base Case Flow		

KLINGLER VELLUM 1021-8

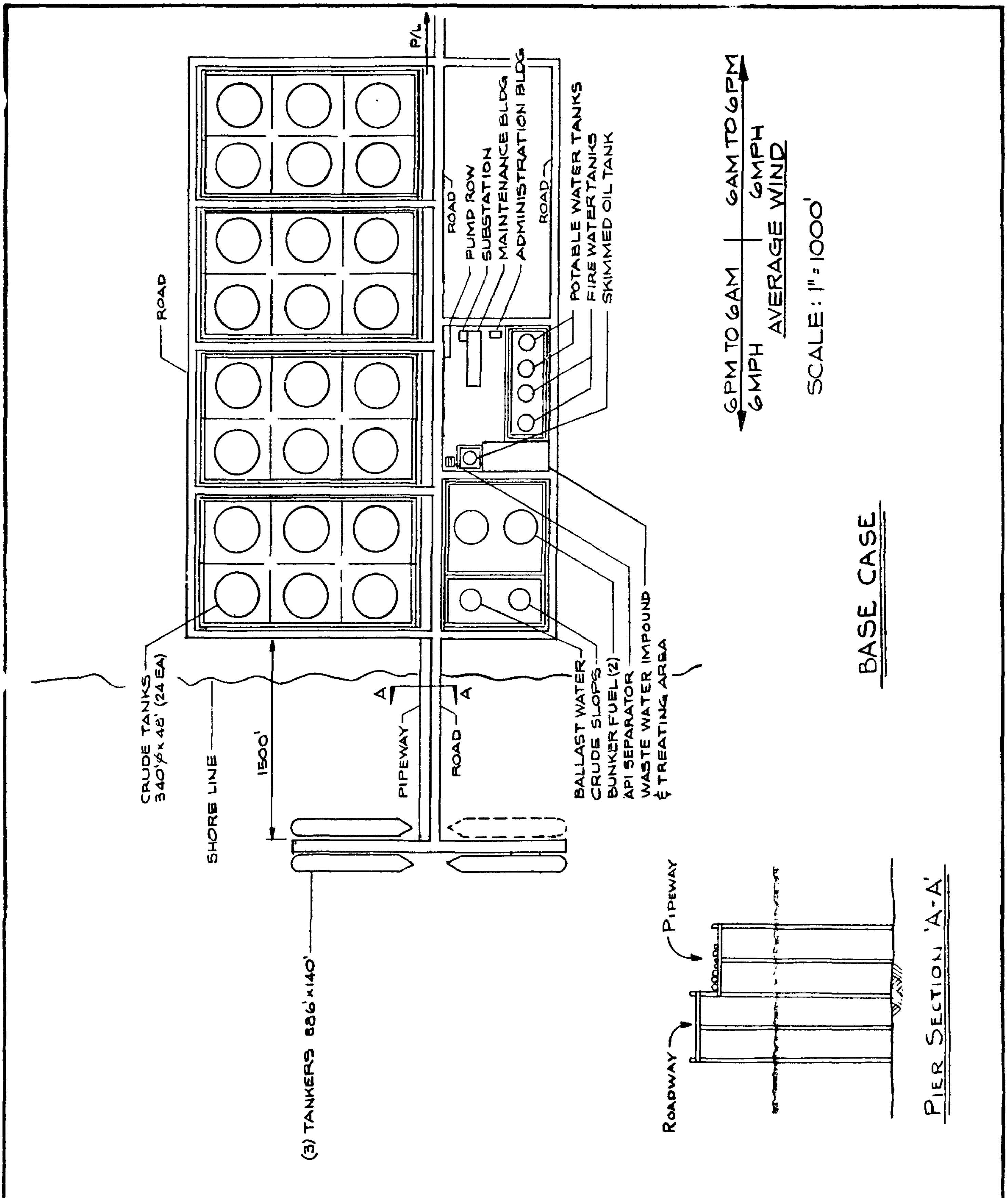
4.2 FACILITY NO. 1

Terminal thru-put rates average 2,250,000 B/CD. Consequently this facility berths three 120,000 DWT tankers, each having the following characteristics:

Overall length	886 feet
Maximum beam	140 feet
Draft (loaded)	52 feet
Freeboard (loaded)	16 feet
Cargo capacity	840,000 bbls
Off-loading rate	74,000 BPH
Ave. ballasting rate	50,000 BPH

Refer to drawing 153-1-1 for Facility No. 1 plot plan and drawing 153-1-2 for a simplified flow sheet. Facility No. 1 contains 24 770M barrel crude oil tanks, each 340' in diameter by 48' high. Bunker fuel oil tanks and potable water tanks are shown on the plot plan, but since these are not related to emissions sources they are not relevant to this study. Incoming crude oil rates vary up to 222,000 BPH from three tankers simultaneously. Outgoing crude oil is discharged into pipelines at rates up to 150,000 BPH maximum. Drawing 153-1-17 illustrates the transfer schedules for Facility No. 1, which encompasses all varieties of operation that are consistent with daily thru-puts. A scenario of ship and tugboat operations within 5 miles of this deepwater terminal has been developed to illustrate the relative impact of marine stack emissions to the alternative vapor recovery systems. Tankers burn No. 6 fuel oil for their boilers in this model, and sea-going tugs run on diesel oil.

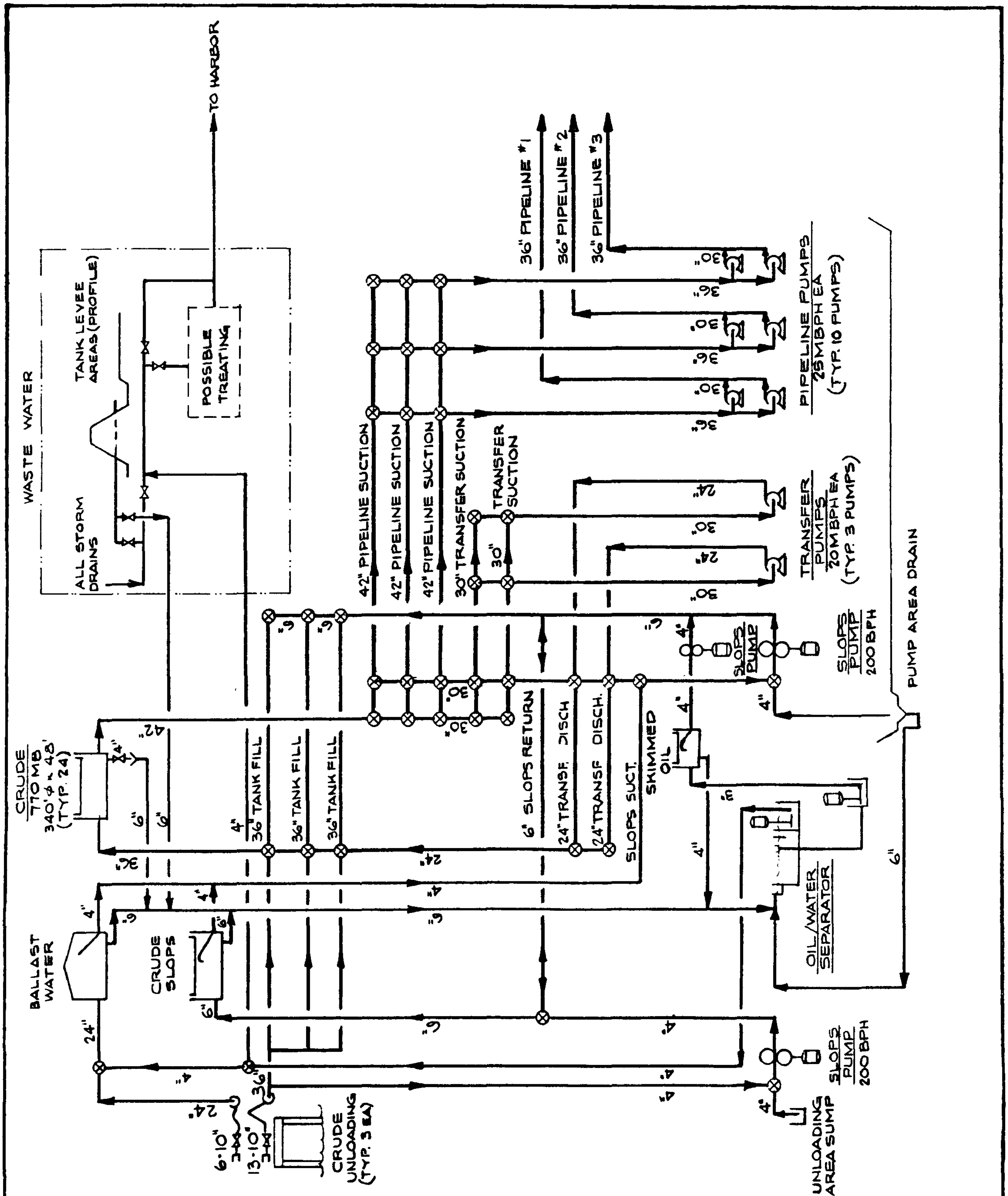
Six tug-hours are used for each full ship arrival and two tug-hours are used for empty ship departures. Ship boiler loads have been reduced for arrival, pumping, stripping and departure operations.



ISSUE	NO	DATE	REVISION	BY	CK	APPVD	ISSUE	NO	DATE	REVISION	BY	CK	APPVD

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER ENVIRONMENTAL PROTECTION AGENCY PLANT FACILITY Nº 1 LOCATION MARINE TERMINAL	DRAWING NUMBER 153-1-1	REV. 0

KLINGLER VELLUM 1021-8



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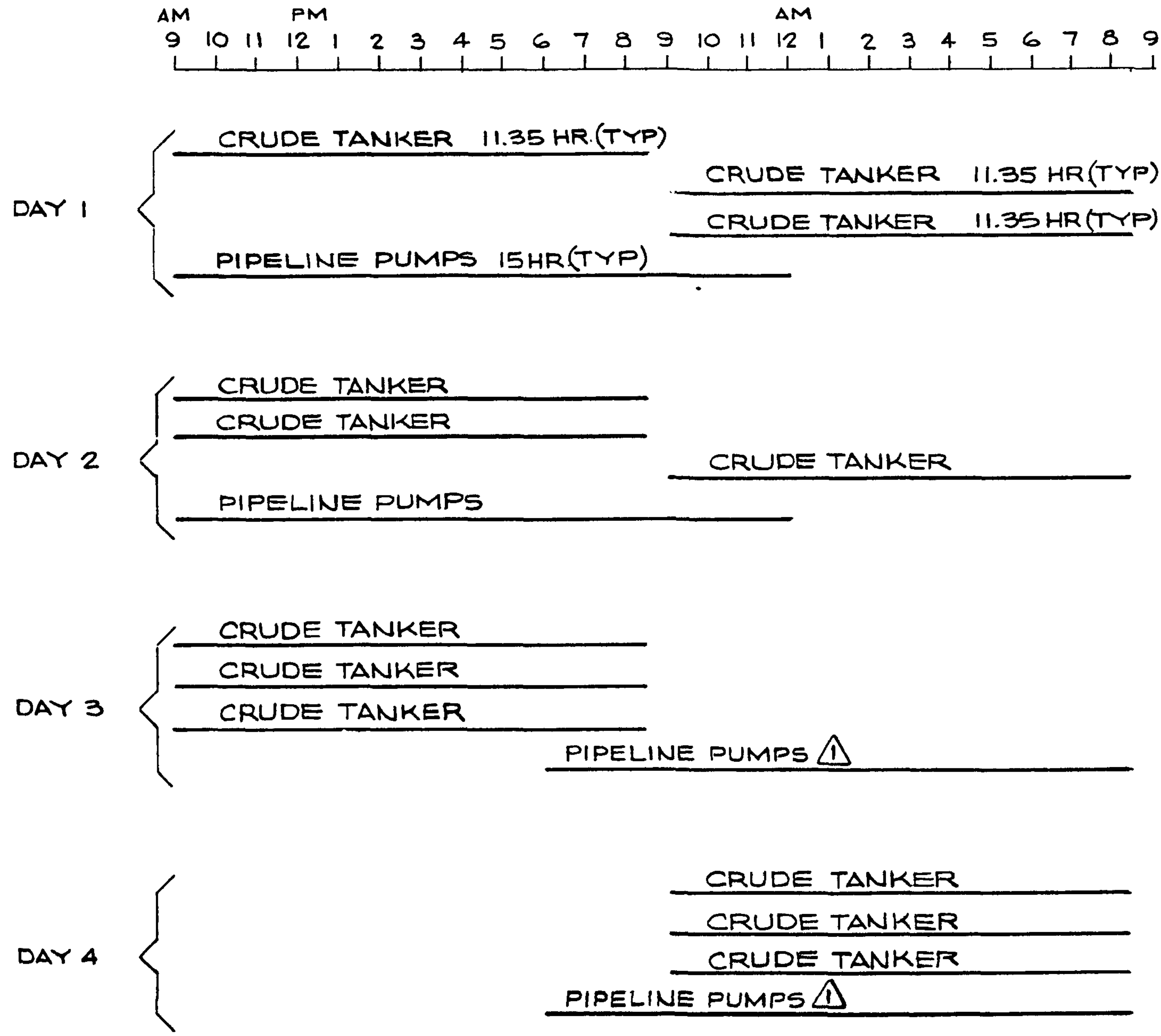
KLINGLER VELLUM 1021-8

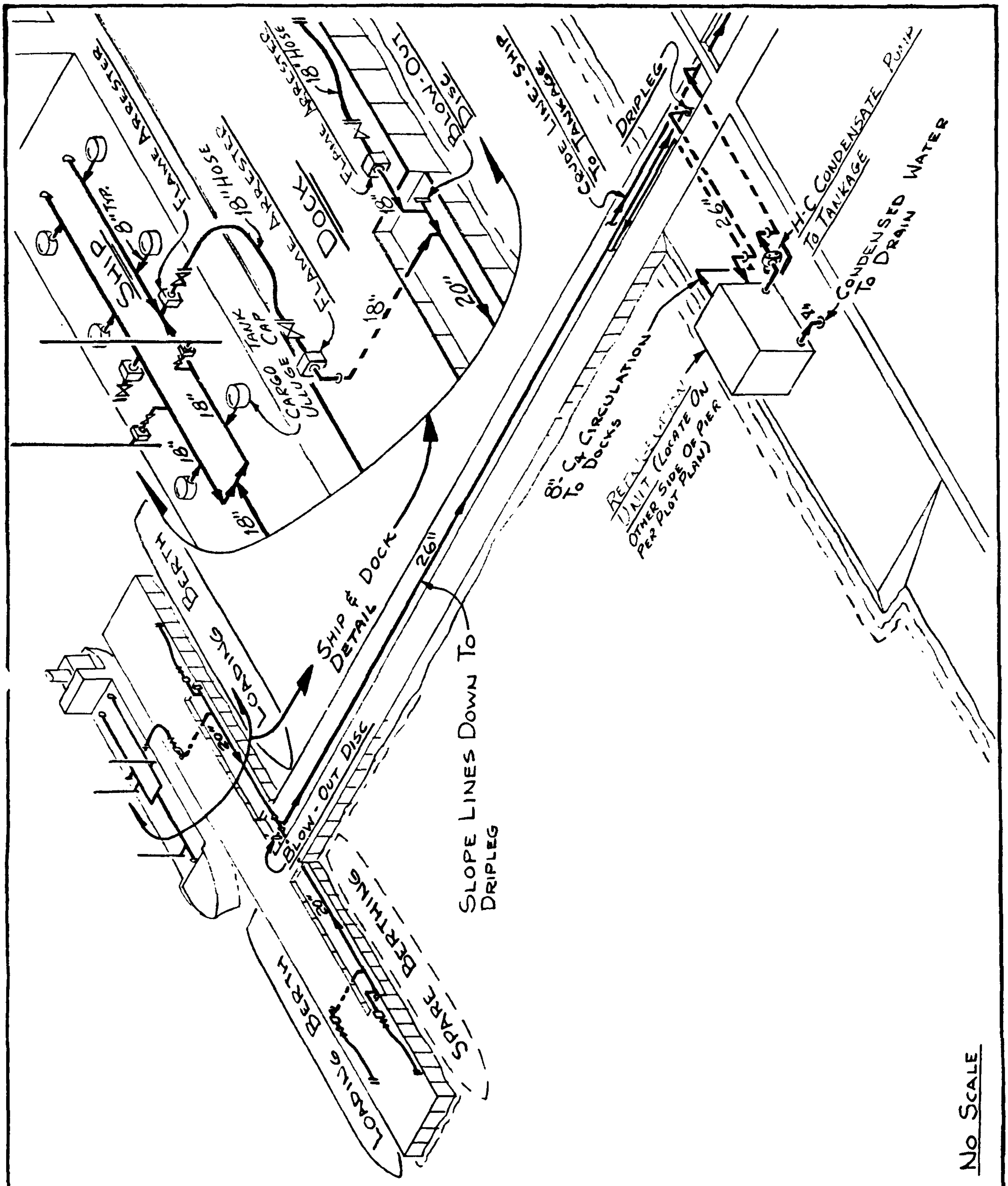
FACILITY Nº 1
TRANSFER SCHEDULE



ISSUE NO	DATE	REVISION	BY	CK	APPVD	ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	RELOCATED P/L PUMPING									

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV.
CUSTOMER	Environmental Protection Agency	153-1-17	1
PLANT	Contract No. 68-02-2838		
LOCATION	Facility #1, Transfer Schedule		

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APPVD	ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	1/25/78	Re-Sized Lines For Inc. Flow	I.C.								

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV.
	CUSTOMER Environmental Protection Agency PLANT Contract No. 68-02-2838 LOCATION Fac. #1, Dock VCS Collection System	153-1-13	1

KLINGLER VELLUM 1021-P

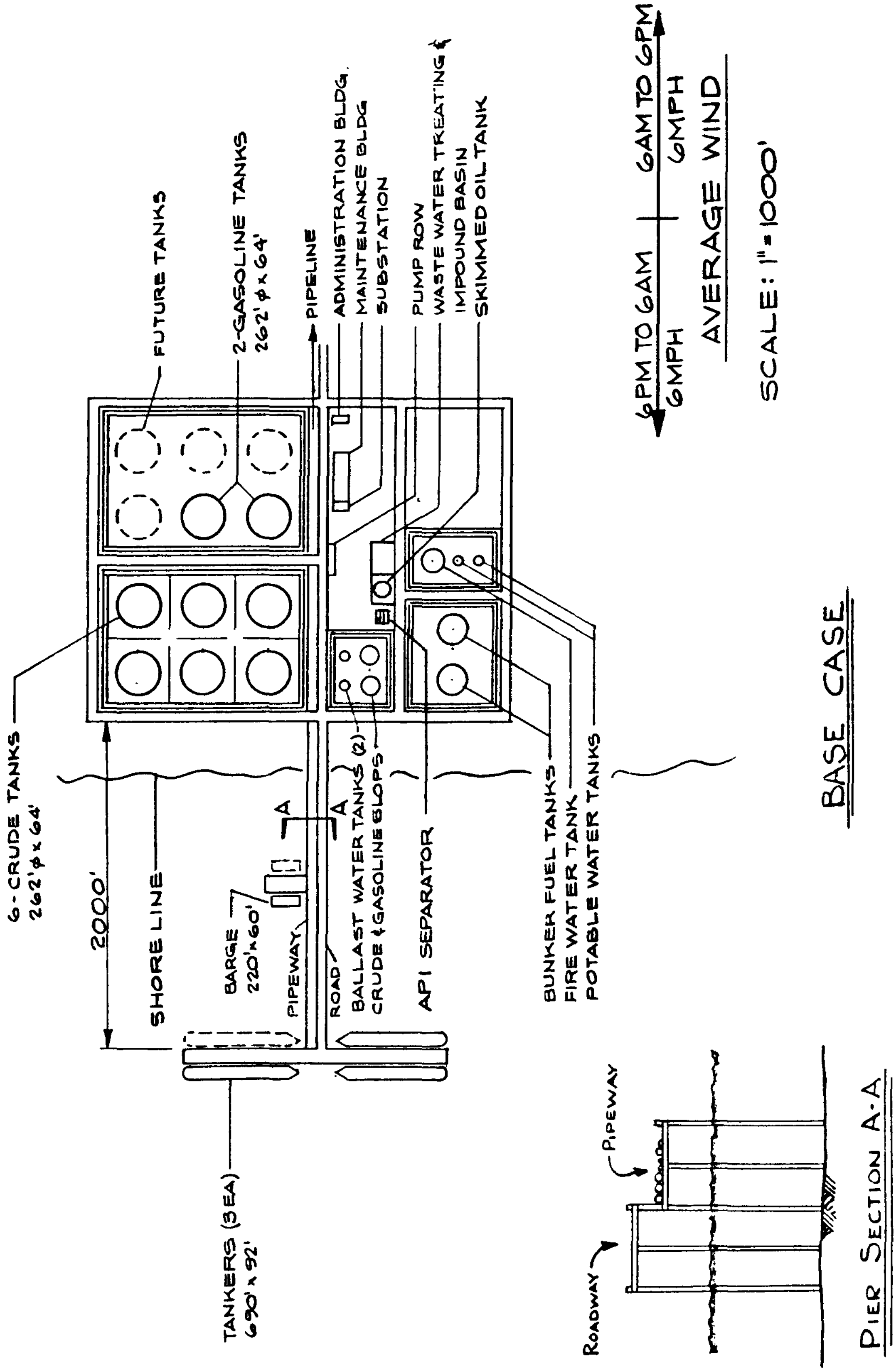
4.3 FACILITY NO. 2

This shallower inland port has a terminal thru-put averaging 525,000 B/CD of crude oil and 175,000 of gasoline, totaling 700,000 B/CD. Docking facilities berth two typical 35,000 DWT crude oil tankers and one similar gasoline tanker and one barge for loading gasoline. Ships and barges have the following characteristics:

	Ships	Barges
Overall length	690 feet	220 feet
Maximum beam	92 feet	62 feet
Draft (unloaded)	35 feet	17 feet
Freeboard (loaded)	12 feet	5 feet
Cargo capacity	235,000 bbls	50,000 bbls
Off-loading rate	30,000 BPH	-
On-loading rate	-	5,000 BPH
Ave. Ballasting rate	20,000 BPH	-

Refer to drawing 153-1-3 and 153-1-4 for Facility No. 2 layout and simplified flow sheet, respectively. This facility contains six 615M barrel tanks for crude oil and two 615M barrel tanks for gasoline, each tank being 262' in diameter and 64' high. Incoming crude oil varies in rates up to 60,000 BPH when two oil tankers are discharging simultaneously, and up to 30,000 BPH of gasoline from one tanker. Outgoing crude rates to pipeline vary up to 35,000 BPH maximum and outgoing gasoline to pipelines up to 12,000 BPH. Gasoline is 55^{o} API and 10 RVP and is loaded onto barges at rates up to 5,000 BPH. The arrival condition of the barge is uncleaned and unballasted, such that the uncontrolled emission factor from gasoline loading is 4.0 lbs of hydrocarbons per 1,000 gallons loaded. The transfer schedule for Facility No 2 is shown on drawing 153-1-18.

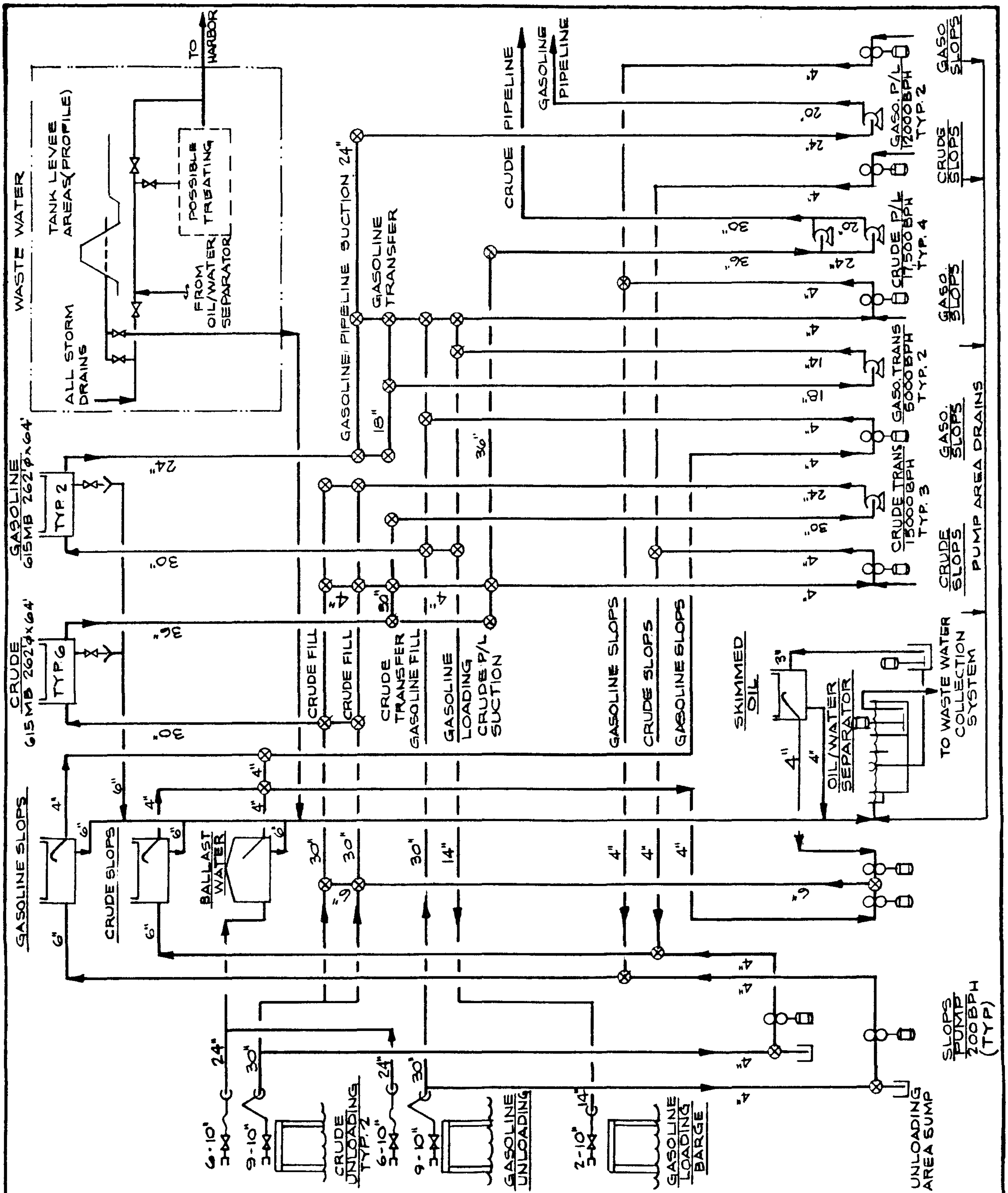
A scenario for ship and tugboat movements has also been developed within 5 miles of this port. These smaller tanks and harbor tugs run exclusively on diesel oil. Four tug-hours are used for each full ship arrival and two tug-hours for each empty departure. Two tug-hours are used for each empty barge arrival and four tug-hours for each full barge departure. Ships' diesel loads have been reduced for arrival, pumping, shipping and departure operations.



ISSUE	NO	DATE	REVISION	BY	CK	APPVD	ISSUE	NO	DATE	REVISION	BY	CK	APPVD

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER ENVIRONMENTAL PROTECTION AGENCY PLANT FACILITY NO. 2 LOCATION MARINE TERMINAL	DRAWING NUMBER 153-1-3	REV. 0

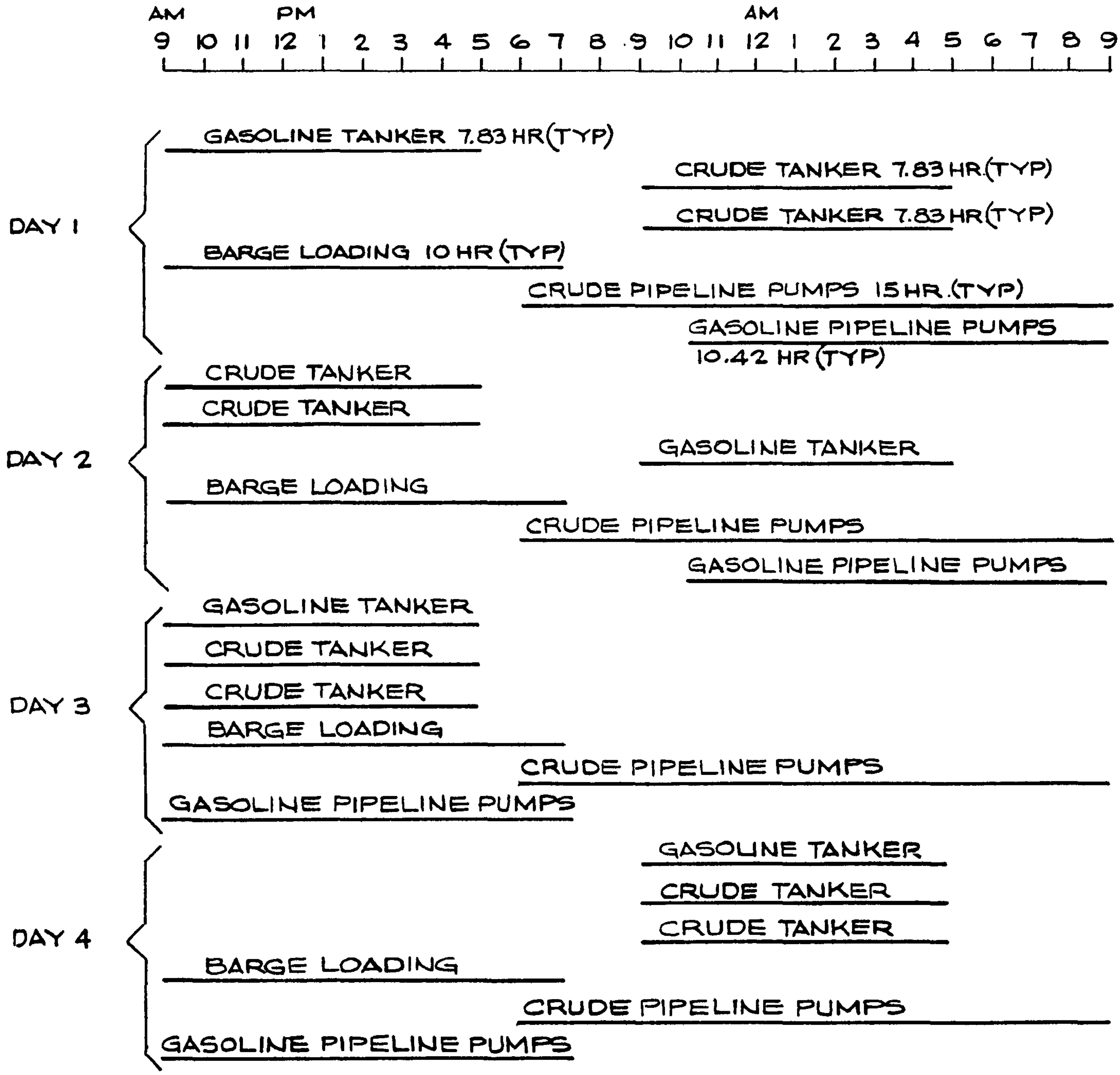
KLINGLER VELLUM 1021-8



ISSUE	NO	DATE	REVISION	BY	CK	APPVD	ISSUE	NO	DATE	REVISION	BY	CK	APPVD

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER ENVIRONMENTAL PROTECTION AGENCY	DRAWING NUMBER	REV.
	PLANT FACILITY Nº 2	153-1-4	0
	LOCATION MARINE TERMINAL		

FACILITY Nº2
TRANSFER SCHEDULE



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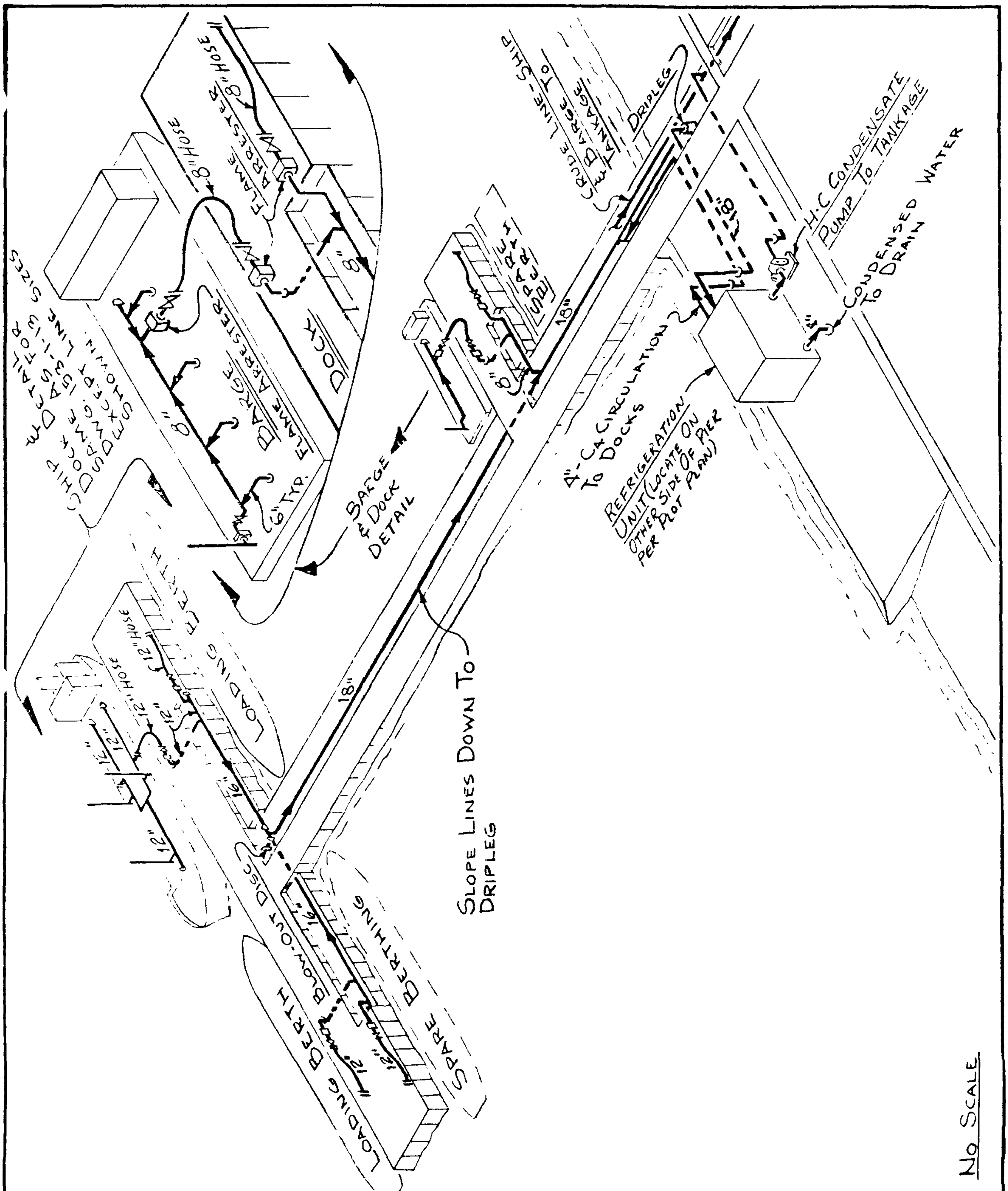
ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV.
	CUSTOMER Environmental Protection Agency	153-1-18	0
	PLANT Contract No. 68-02-2838		
	LOCATION Facility #2, Transfer Schedule		

KLINGLER VELLUM 1021-8



Issue No	Date	Revision	By	CK	APPVD	Issue No	Date	Revision	By	CK	APPVD
1	12/16/77	Add Water Seal Pot	I.C.								
2	1/25/78	Re-Size Lines For Incr. Flow	I.C								

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA			DRAWING NUMBER	REV.
	CUSTOMER	Environmental Protection Agency	153-1-15	2
	PLANT	Contract No. 68-02-2838		
	LOCATION	Fac. #2, Dock VCS Collection System		

KLINGLER VELLUM 1021-8

5.0 ALTERNATIVE VAPOR CONTROL SYSTEMS

Vapor control is manifested by the collection and disposition or containment of a non-explosive mixture of gases in order to prevent pollutant components from escaping to atmosphere. A mixture of gases results from the effect of the partial pressure of pollutants in this contiguous gas phase over the parent liquid. The mixture of gases is referred to herein as "blanket gas", which includes "hydrocarbons", the latter being a pollutant. Blanket gas, therefore, is a media for conveying the pollutants to some disposition, without causing structural pressure damage to the parent liquid containers. Thus, excessive physical vacuums or pressures and chemical explosive or implosive mixtures must be avoided. Means are provided to maintain oxygen concentrations below safe levels, or to warn operators to take necessary precautions when certain levels are reached.

The saturation composition of crude oil vapors and gasoline vapors in air at $75^{o}F$ and atmospheric pressure is about (4.6/14.7) (100) and (6.8/14.7) (100) percent, respectively, in the models herein. These compositions are approximately one third and one half of their upper explosive limit in air (UEL=84 vol % H-C), but air has not been considered as an alternative blanket gas media because of safety reasons. Air is saturated by gasoline in some commercial truck loading rack vapor recovery packages in order to render the mixture of gases too rich to burn. This has been discounted, in this study, primarily because the margin of safety from explosive conditions is considered inadequate in view of the size of these terminal volumes and the consequences of explosions. Secondly, the vaporizing process itself must pass through the explosive range. If the true vapor pressure of the parent liquid would drop from 4.6 to 2.2 psia during vaporization, for instance, that equilibrium vapor-air mixture produced would be explosive.

Gas blanketed systems in this study are assumed to be saturated at the abovementioned compositions, as defined from Raoults' and Dalton's Law for ideal gases. Cone roof tank breathing and working losses, floating roof tank standing and withdrawal losses, ballast emissions, and barge loading emissions, also have been assumed in this comparative study to produce hydrocarbon emissions of the magnitudes defined by Supplement 7 of AP 42. Hydrocarbons recovered by refrigeration and returned to terminal throughputs, or those lost to incineration, have conservatively included breathing loss volumes along with displacement volumes. Actual hydrocarbon vaporizations into saturated hydrocarbon gas phases, however, would be substantially less than those defined by Supplement 7 of AP-42 because mass transfer diffusion potentials would disappear. The continuous removal of an equal amount of vaporized hydrocarbons from the enclosed blanket media is assumed in this study to off-set saturation equilibria to an extent that these published emission factors prevail. This assumption, while being expedient, also helps to magnify comparative differences between alternative vapor control systems. It should be kept in mind, therefore, that actual breathing losses into closed blanket gas systems would be substantially less than those in this study, and that refrigeration power requirements and incineration losses would also be less by this difference in volumes of saturated hydrocarbons handled.

5.1 UNSELECTED SYSTEMS

A number of vapor recovery systems have been proposed for terminal applications in recent years. Many have been considered, but not selected, for this study.

- Refrigerated cargoes have not been selected for study because of excessive refrigeration and cargo pumping cost in both the terminal and the tankers, plus capital investments at the terminal to maintain cold temperatures.
- Burning waste blanket gas in tanker boilers has not been selected for study in view of a limited application and the danger of positive fire box pressures in boilers back-flashing into cargo volumes.
- Venting secondary seals on external floating roof tanks has not been selected for study because negative pressures in the long narrow spaces between the two seals would stimulate both the wind effect on the primary seal increasing hydrocarbon emissions and air leakage through the secondary seal causing explosive gas mixtures. Positive pressure with inert gas on the other hand, would also increase the wind effect on the primary seal and emissions through the secondary seal, increasing hydrocarbon emissions and causing excessive inert gas demands.
- Water displacement storages have not been selected for study because Sea Dock studies showed these systems to be excessively capital intensive.
- Variable vapor volume storages equal to total terminal volumes have not been selected for study because other (unpublished) studies have shown these systems to be too costly, and too vulnerable to atmospheric leakages.

- High pressure compression and storage of excess blanket gas has not been utilized because of high energy and pressure vessel storage costs.
- Commercial vapor recovery packages have not been selected because these units, which are utilized at truck loading racks, have not been designed for such large capacities. In effect, their unit features, namely saturation, compression, absorption and refrigeration have been utilized where applicable to the scope of this effort.
- Hydrocarbon/air saturation methods to render blanket gas too rich to burn, as in some commercial truck loading vapor recovery units have not been selected, as explained in section 5.0, p. 32.

It has been decided that evaluations of the following three methods of vapor collection and/or disposal fall outside the scope of this work effort:

- Absorption systems, which may well have feasible application in these models.
- Catalytic conversion methods, which may feasibly reduce fuel gas consumption in the oxidation of hydrocarbon emissions to atmosphere.
- Adsorption systems, which may have a limited role also in these models.

5.2 SELECTED SYSTEMS

The systems selected fall into three basic categories regarding tankage emission controls:

1. Minimum investment (Cases I and II)
2. Natural gas blanket media (Cases III, IV, and V)
3. Non-combustible gas blanket media (Cases VI and VII)

Ballast emissions are either refrigerated or incinerated. Refrigeration vapor emissions are either vented to atmosphere or returned to the blanket gas system (Cases V and VII). Some of these cases were selected with the understanding that, while their economics may be obviously in disfavor, their economic evaluations were necessary to illustrate the comparative value of other cases. Each case has an alternative system wherein internal floating roof tankage is used instead of cone roof tankage or, as in Case I, external floating roof tankage.

These hypothetical terminal facilities do not address their vapor control systems to the handling of sour crudes. The basic change to the systems selected, if crudes were to be handled whose vapors would be sour enough to contaminate gasoline storages, would be to separate crude and gasoline tankage vapor collections and recycled blanket gas distributions. Marine contaminations would not occur in the scenarios chosen for this study. Separate flexible diaphram gas receivers and floating roof gas holders would, therefore, be used for crude and gasoline tankage vapors in Facility No. 2, and separate blanket gas piping would be needed in Cases IV, V, VI, and VII. In these cases where blanket gas is recycled, sour vapors should be treated as proposed for Cases IV and V regarding sulfur removal. Here sponge iron replacements would increase in direct proportion to the amount of H_2S that is removed. The effect on vapor control arrangements for handling sour crudes, meaning those whose vapors contain hydrogen sulfides, is described for each vapor control case below.

5.3 CASE I

Case I differs from the Base Case only by refrigerating ballast emissions. Case IA differs further by having internal instead of external floating roof tanks. Refer to drawings 153-1-6 and -6A for both facilities, and to Tables 1 and 2 for relative economic values.

Ballast emissions are explosive, according to the latest EPA emission factors for ballasting into air-ladened crude or gasoline tanker compartments[1]. Emissions from loading dedicated unballasted air-ladened gasoline barges are almost too rich to burn. A single collection header is used to collect these emissions from tankers and barges to an enclosed 3" water seal and refrigeration unit on shore. Collection piping, which is about 1700 ft. long in Facility No. 1, and some 500 ft. further in Facility No. 2 has been sized for 2 psig working pressures in tanker and barge compartments[3,4]. Marine vessel cargo flanges are connected to dock piping with hose connections. Flame arrestors are located between the 3" water seal and the refrigerator on shore, at each valved hose connection on the docks, and at each valved ship-board hose connection. One-quarter inch thick collection piping is located on the wharfs so as to cause the least amount of detonation damage. More importantly, detonation is avoided by purging from the extremities of each collection header with recycled normal butane gas to and from the refrigerator, in order to render the pipe contents too rich to burn. Heat exchange within the refrigerator is used to vaporize these condensed hydrocarbons at 30 psig. Oxygen analyzing recorder controllers regulate the amount of purge gas into each vapor collection header. Appropriate alarms are sounded if oxygen concentrations above safe levels are recorded. This slave butane circulating system consumes only 3.9 MM Btu/Hr at the worst conditions, (i.e. having 3 tankers ballasting simultaneously in Facility No. 1) in order to vaporize enough butane to increase hydrocarbon pipeline concentration from 3.37 vol % to 20 vol %. Revaporization is at -32°F. About 200 operating horsepower is, therefore, required for this recycle purge at design conditions in Facility No. 1, and about 75 horsepower at most in Facility No. 2.

Refrigerator horsepower and piping costs could be reduced by placing the refrigeration package on the docks, adjacent to the ships and barges. The enrichening butane recycle might then be omitted by reason of having smaller potentially explosive volumes. However, this study has considered only remote refrigeration, in a pressurized housing, with gas blanketing throughout all collection branches, because it is the safer arrangement. Accidents do occur at wharfs, expecially while docking during inclement weather. A multi-million dollar refrigeration system, containing non-explosion proof electrical gear in a pressurized housing on the dock could become hazardous. The elevated housing air intake, for instance, could inhale a vapor blanket expelled by a tanker maloperation.

Refrigeration installation and operating costs are for temperatures reduced to -170°F in order to minimize propane emissions from virgin crudes. Calculated hydrocarbon emissions amount to 925 short tons per year none-the-less, before applying loading factors, for Facility No. 1, and 396 short tons per year for Facility No. 2. H_2S from sour crude vapors would also be emitted.

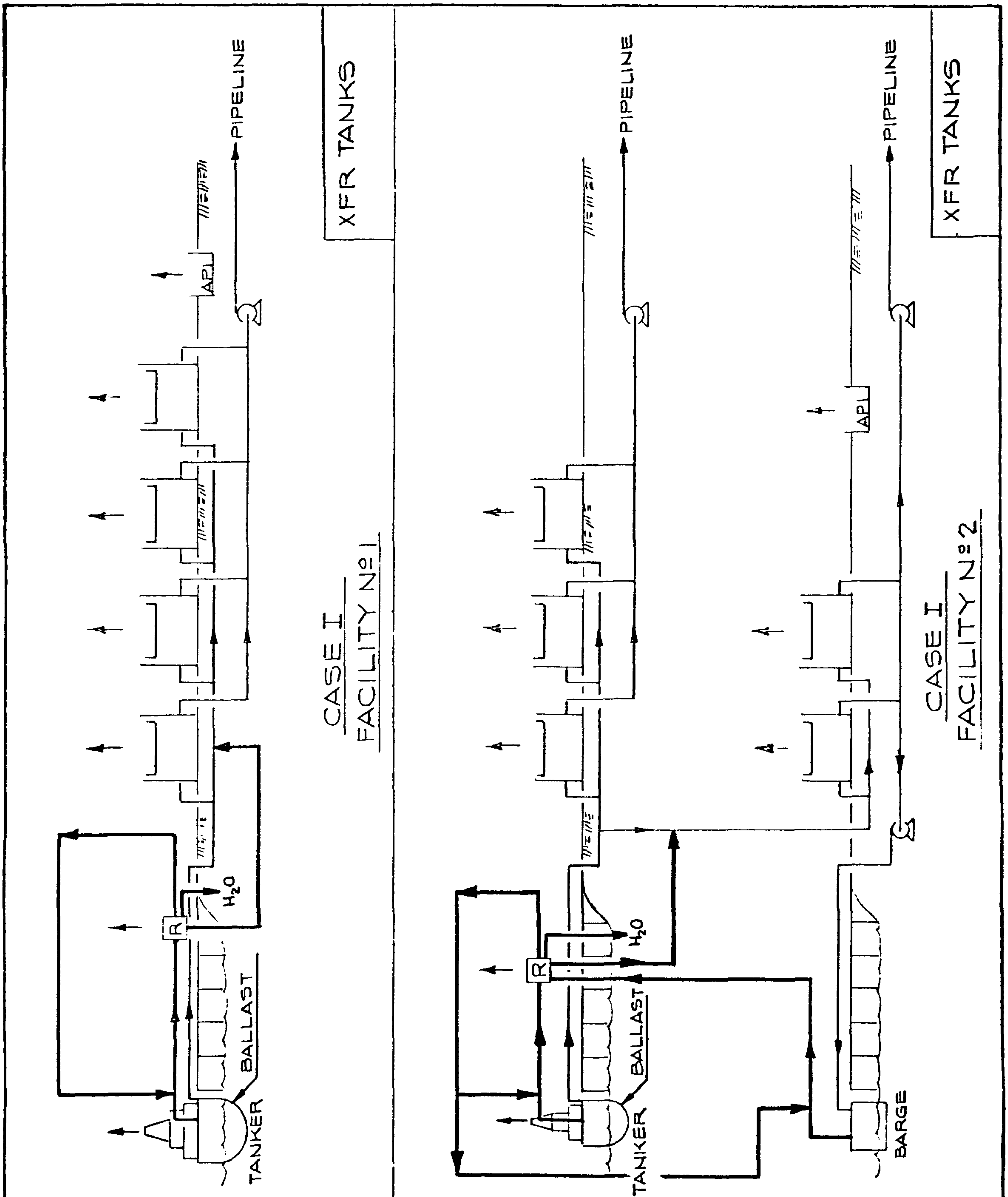
Hydrate formation problems have been considered minimal at these low pressures with proper precooling to the hydrate point, and heat recovery sections that conduct defrost-cycle vapors back to the refrigerating section. See paragraph 9.2.7. The above emissions calculated from vapor pressure equilibrium are expected to include any losses resulting from defrosting hydrates.

Controlled versus uncontrolled Base Case emission in short tons/year and installed vapor control costs are:

	EMISSIONS ST/Y					COST
Facility No. 1	H-C	NO_x	SO_x	CO	Part.	$ M
Base Case	2890	148	111	40	11	-
Case I	1387	148	111	40	11	2,630
Case IA	1158	148	111	40	11	6,355
Facility No. 2						
Base Case	2578	280	20	136	0	-
Case I	515	280	20	136	0	1,392
Case IA	441	280	20	136	0	2,260

Case I is the most cost effective, and Case IA the next most cost effective, control system evaluated. "Cost effectiveness" is a measure of those investment and operating costs required to reduce a ton of hydrocarbon emissions from base case conditions. The best cost effectiveness is the lowest cost value. Refer to Tables 1 and 2 for Facilities No. 1 and 2 respectively. The primary reason for these cases being the most cost effective for both facilities is that they direct their efforts to emissions from marine vessels, from which 75% of all hydrocarbon emissions from Facility No. 1 and 89% of all those from Facility No. 2 come. Vapor control systems to remove tankage emissions are, therefore, relatively costly.

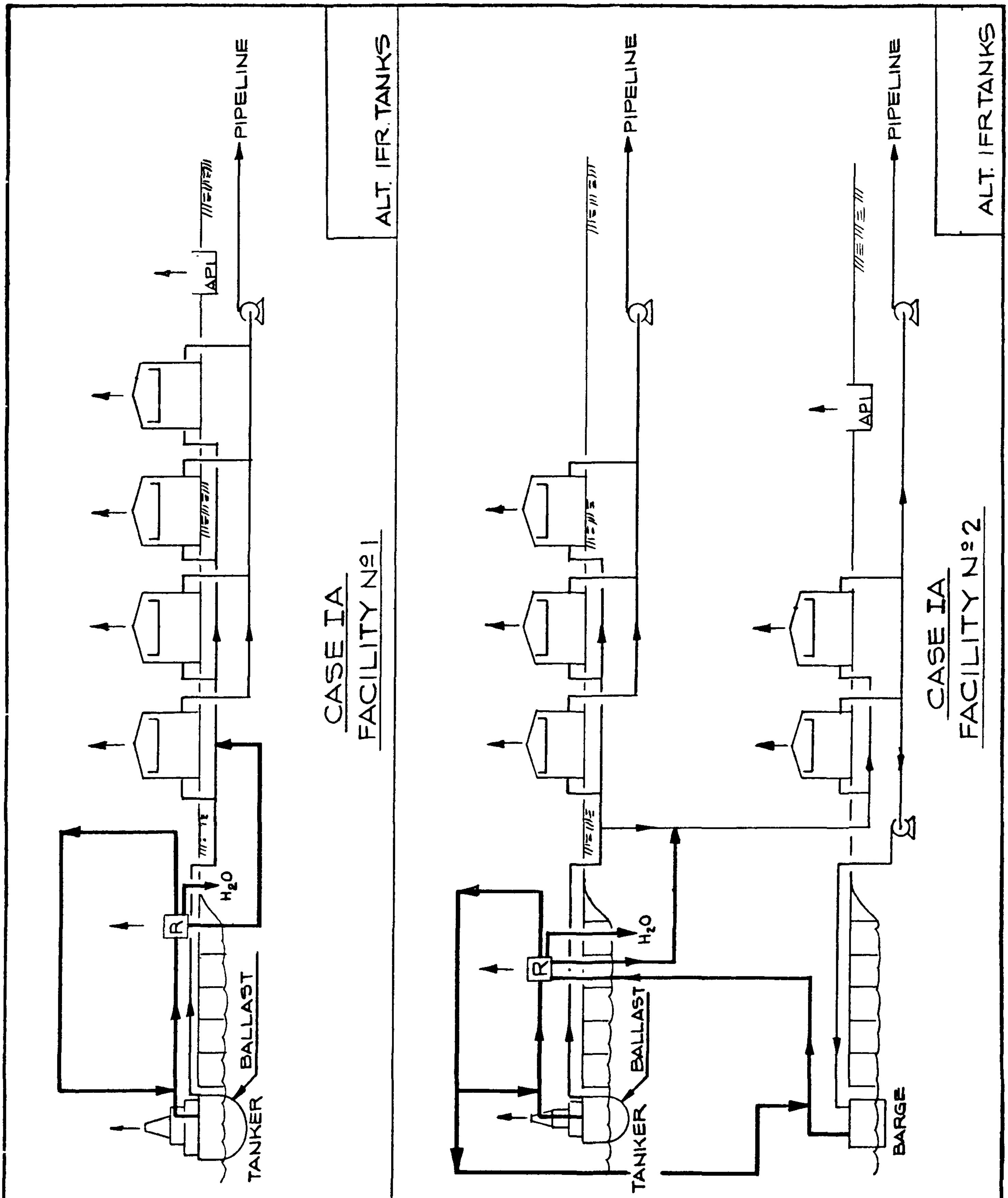
Case IA clearly shows the cost effectiveness of internal versus external floating roof tankage, based upon the arbitrary criteria only that an average 4 mph wind effect prevails in the former and a 6 mph wind effect prevails for the latter. With these ground rules, the cost effectiveness is less than half as good by having internal floating roofs in the larger Facility No. 1 and somewhat better in Facility No. 2. Case IA is the only example of such tankage with conventional air vents on the upper shell. Other alternate cases utilize gas blankets with internal floating roof tankage. Air-vapor mixtures in these ullages can become explosive, especially after fast withdrawals from small tanks, but both costs and explosive conditions are related to tank sizes, amongst other things. Refer to paragraph 9.2.2.



ISSUE	NO	DATE	REVISION	BY	CK	APPVD	ISSUE	NO	DATE	REVISION	BY	CK	APPVD
	1	12/12/77	REMOVED INCINERATOR										

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract #68-02-2838	153-1-6	2
	LOCATION	Case I Flow		

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APPVD	ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12/12/77	REMOVED INCINERATOR									

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract #68-02-2838	153-1-6A	2
	LOCATION	Case I Flow		

KLINGLER VELLUM 1021-6

5.4 CASE II

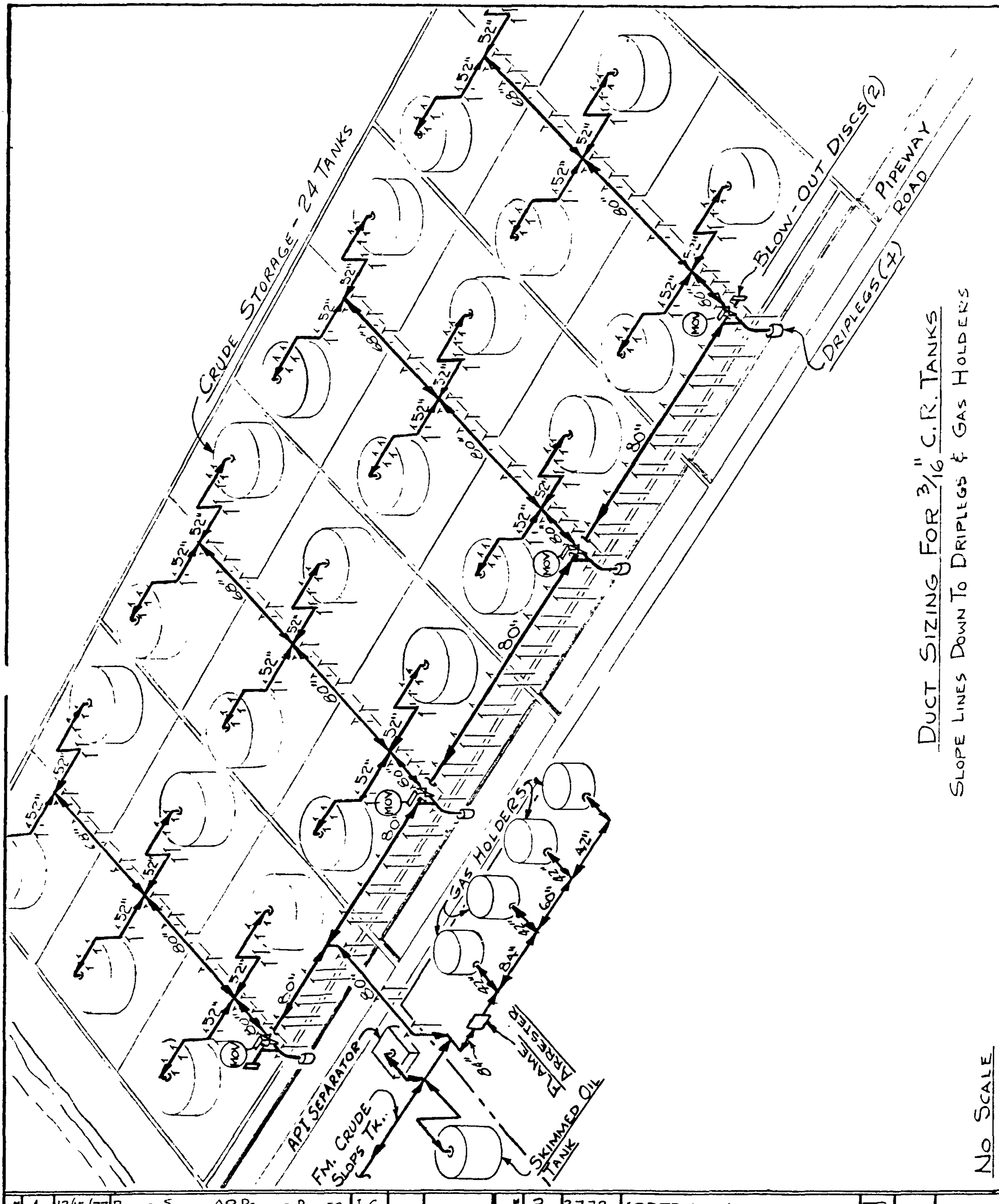
This case incinerates ballast and gasoline barge loading emissions directly and flares net excess blanket natural gas from tankage directly. No refrigeration is used. Drawings 153-1-7 and 7A describe this application to both facilities. Tables 1 and 2 present relative economic values.

The same safety precautions are taken for explosive ballast and barge emissions here as in Case I, except that fuel gas for incineration is used instead of the slave vaporization system used in Case I, and aluminum emission blowers are used in this case to provide pressures that will assure smokeless burning characteristics.

Fuel gas is purged into the extremities of the dockside vapor collection headers, rendering the pipe contents slightly too rich to burn, at about 20 vol % hydrocarbons. At worst conditions, (i.e.: ballasting three tankers at once in Facility No. 1) this requires 169.7 MSCFH of gas. Gas purge flows are regulated by oxygen analyzing recorder-controllers. The enclosed 3" water seal and flame arrestor preceding the incinerator in this case is more critical in preventing backflashes than they were in Case I because constant ignition prevails at the incinerator. Consequently, automatic controls must maintain the water seal in the vessel with fail safe redundancy and alarms. A small gas purge after the seal and through the flame arrestor is used to denote a forward flow of gases. Any failure in the forward flow automatically shuts off all fuel gas to the incinerator, including pilot gas, and sounds appropriate alarms.

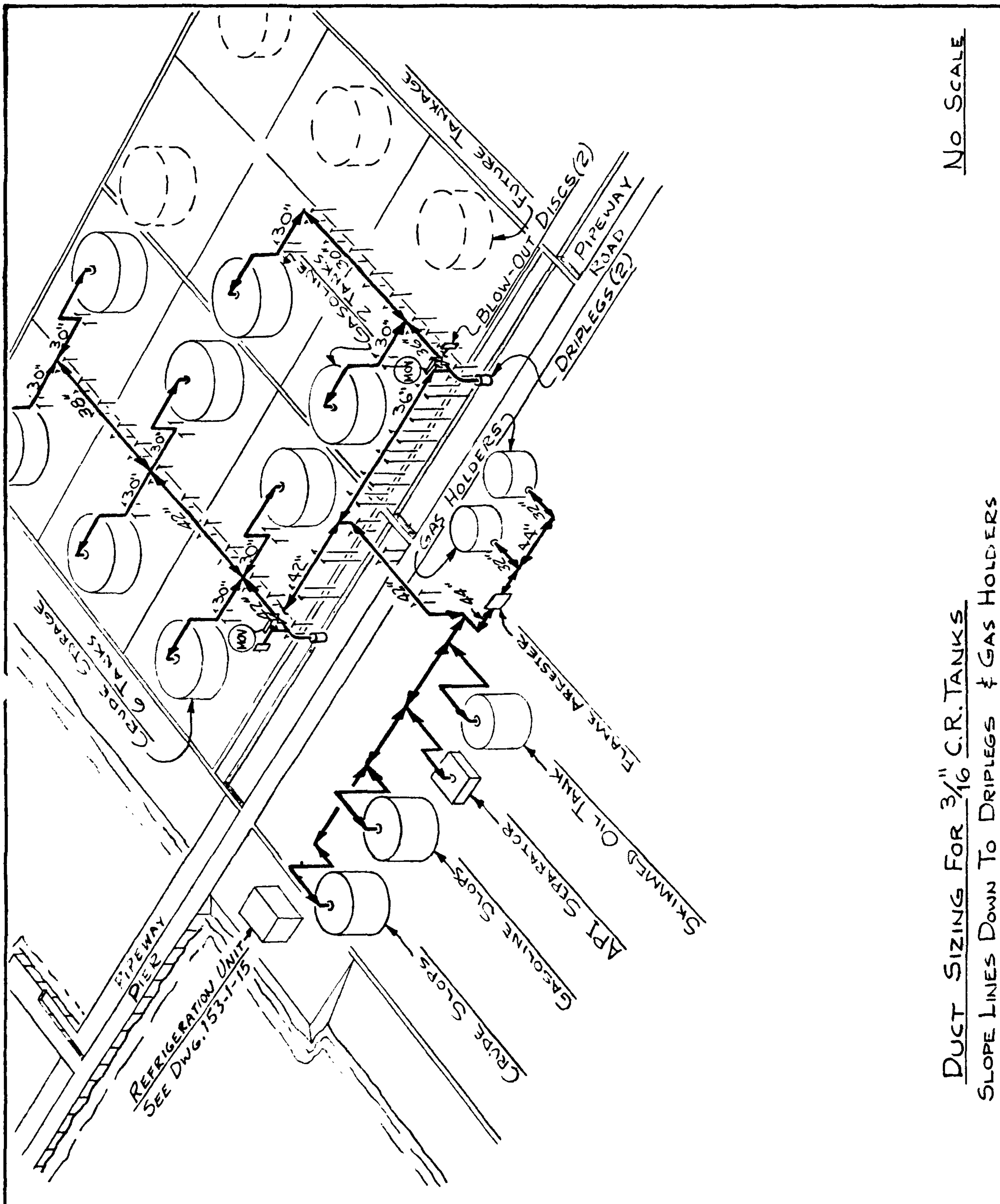
Natural gas under about 60 psig is distributed directly to storage tankage whenever tank ullage pressures reach 0.5 ounces per square inch (osi) vacuum. Gas valves are set to start opening at 0.5 osi vacuum and to be fully open at 1.3 osi vacuum. Refer to Table 3, paragraph 9.1.1. Cone roof tanks in Case II (both facilities) and internal floating roof tanks in Case IIA (both facilities) both have 3/16" fixed steel roofs with vacuum relief valve settings of 2.78 osi vacuum. Multiple PSV's are needed for each major storage tank in both facilities, and a blanket gas tank inlet is located near each PSV to prevent any pressure lag from opening the vacuum PSV to atmosphere. One common pressure control valve (PCV), however, is used for blanket gas per tank in both facilities. See paragraph 9.3.

Net excess blanket gas expulsions are collected in flexible diaphram gas holders at 0.2 osi. Thus only 0.3 osi of pressure drop motivates blanket gas flow through a flame arrestor and into these holders. Vapor collection ducts have been sized accordingly. Tankage vapor collection piping is shown on drawings 153-1-14 and 153-1-16 for Facilities No. 1 and 2. Four holders are used in Facility No. 1 and two in Facility No. 2. If crudes with sour vapors are to be handled in Facility No. 2, contamination of gasoline from crude vapors can be avoided by collecting crude and gasoline vapors separately into separate gas holders. When the bags in these groups of holders are full, a bag level switch activates a blower that transfers the gas first from one gas holder, then from another, into a water-sealed ground flare. Storage tank impulsions, due to breathing inhalations and/or pumpout replacement volumes, will back-flow blanket gas from these gas holders before new purchased natural gas is admitted into storage tankage because 0.7 osi pressure drop is available in that direction (versus 0.3 osi for expulsions) before the PCV's begin to open.



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12/15/77	Revised System ΔP, Removed Blower	I.C.		
2	1/5/77	Added Duct Supports	I.C.		
3	3-7-78	Added MOV	TS		

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER Environmental Protection Agency PLANT Contract No. 68-02-2838 LOCATION Facility #1, Vapor Collection Layout	DRAWING NUMBER 153-1-14	REV. 3



Issue No	Date	Revision	By	Ck	Appvd	Issue No	Date	Revision	By	Ck	Appvd
1	12/14/77	Rev. System AP, Moved Blower	I.C.			3	3-7-78	ADDED MOV	TS		
2	1/5/77	Added Duct Supports	I.C.								

			Drawing Number	Rev.
ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	153-1-16	3
	PLANT	Contract No. 68-02-2838		
	LOCATION	Facility #2 Vapor Collection Layout		

KLINGLER VELLUM 1021-8

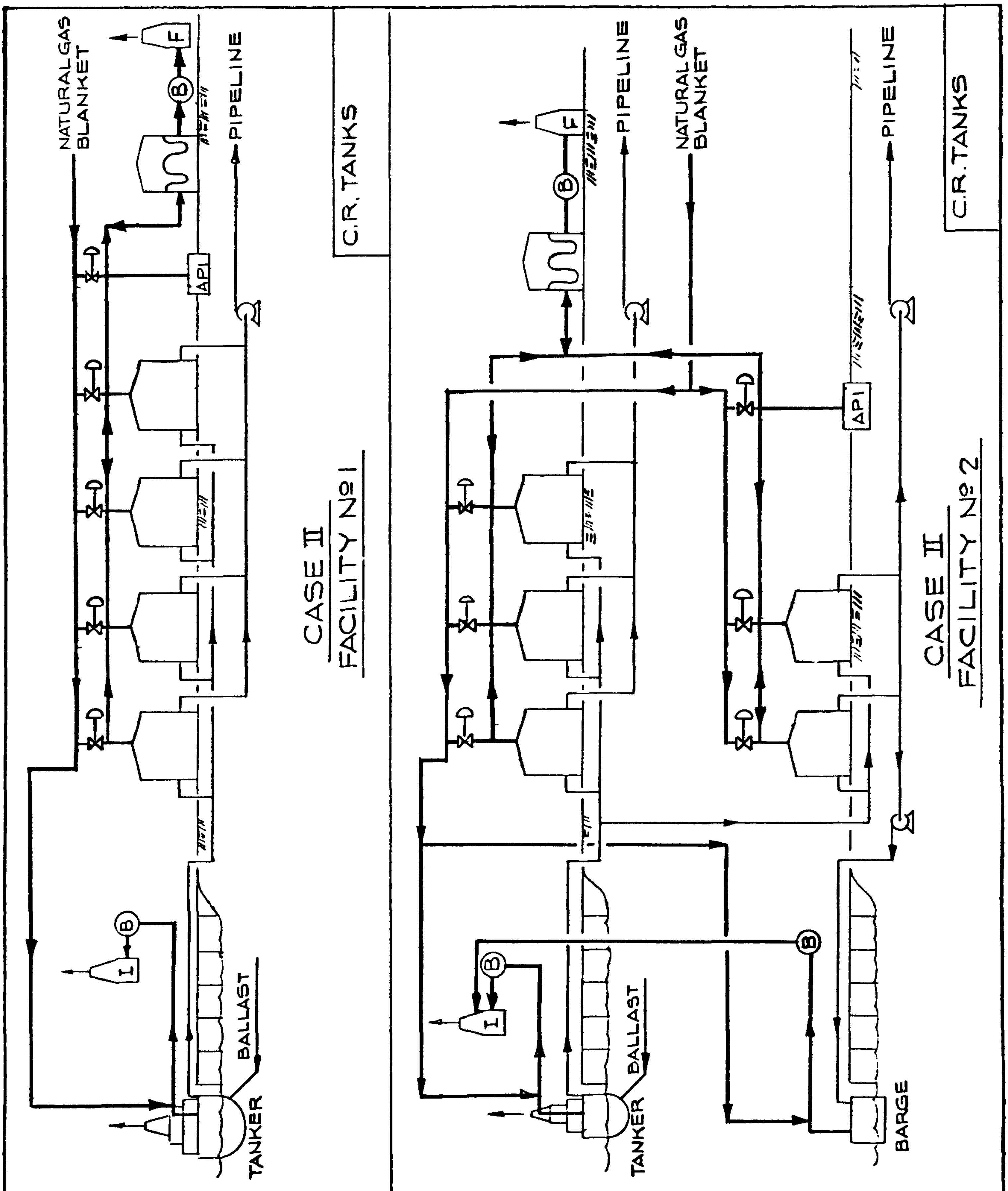
In more capital intensive vapor control systems, Cases IV, V, VI and VII, the reuse of net excess blanket gas, before new gas sources are used, is assured by boosting excess blanket gas from the flexible diaphram receiver tanks into floating roof gas holders at 7.0 osi pressure with blowers. From there blanket gas needs are supplied by a separate distribution and PCV system to each storage tank. Floating roof gas holders are relatively expensive, costing about $2.00/cubic foot. With natural gas costing roughly $2.00/1000 cubic feet, the direct payout in natural gas by such storages requires more than 8 years, excluding the cost of separate distribution systems.

Controlled versus uncontrolled Base Case emissions in short tons/year and installed vapor control costs are:

	EMISSIONS ST/Y					COST
Facility No. 1	H-C	NO_x	SO_x	CO	Part.	$ M
Base Case	2890	148	111	40	11	-
Case II	78	267	114	57	29	2,720
Case IIA	77	228	111	51	23	11,290
Facility No. 2						
Base Case	2578	280	20	136	0	-
Case II	61	335	21	144	8.3	1,940
Case IIA	61	337	20	144	8.5	3,680

Although it is not evident in the tabulation above, the value of restraining vaporizations in fixed roof tankage by internal floating pans is dramatically quantified by Case II control systems. This is the only case where tankage emissions are completely wasted. Those from cone roof tankage total $7,922,000 annually in lost crude from Facility No. 1, and $3,423,000 annually in products from Facility No. 2. Losses from internal floating roof tankage in Case IIA, however, amount to only $98,200 and $38,000, respectively. On the other hand, internal floating roof tankage costs much more and requires greater blanket gas demands because tank withdrawals therefrom are not partially replaced by surface vaporizations to the extent they are in cone roof tankage. Once the blanket gas is drawn into the system from outside, in this case, it is ultimately incinerated. These off-setting effects do not manifest themselves in the above tabulation, and the cost effectiveness of those negative credits to Case II become relatively inconsequential. Refer to Tables 1 and 2.

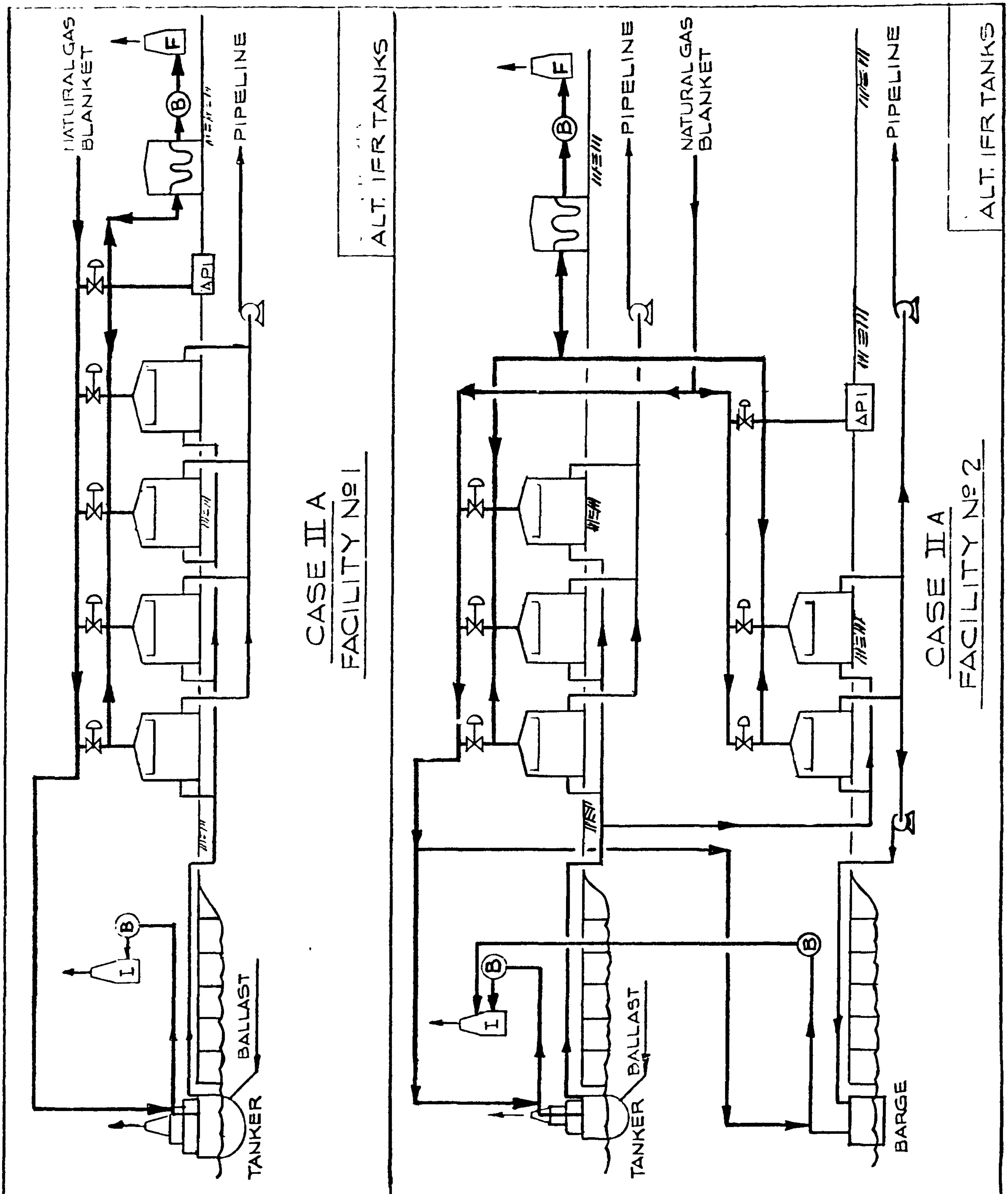
Sour crude vapors would convert stoichiometrically to SO_x from the incinerators in this case. Since this study is not based upon a specific crude source, and sulfur levels have not been defined, the SO_x emissions tabulated above do not include sulfur sources from crude or gasoline vapors.



ISSUE	NO.	DATE	REVISION	BY	CK	APPVD	ISSUE	NO.	DATE	REVISION	BY	CK	APPVD
	1	12/12/77	Revised Case No.										
	2	1/13/77	Combined Incinerators										

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA			DRAWING NUMBER	REV.
	CUSTOMER	Environmental Protection Agency	153-1-7	2
	PLANT	Contract #68-02-2838		
	LOCATION	Case II Flow		

KLINGLER VELLUM 1021-8



ISSUE	NO	DATE	REVISION
	1		Revised Case No.
	2	1/13/77	Combined Incinerators

ROBERT BROWN ASSOCIATES
CARSON, CALIFORNIA

CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
PLANT	Contract #68-02-2838	153-1-7A	2
LOCATION	Case IIA Flow		

KLINGLER VELLUM 1021-8

5.5 CASE III

This case uses refrigeration for both direct marine emissions and net excess blanket natural gas from cone roof tankage. Emissions from tanker ballasting and gasoline barge loadings are handled as outlined for Case I. Refer to drawings 153-1-8 and 8A for this application to both facilities, and to Tables 1 and 2 for relative economic values.

A study was made for this case to burn refrigeration vapor effluent from marine emissions by only condensing those hydrocarbons in excess of that needed to support combustion. The only substantial amount of marine hydrocarbons condensed, however, became those relatively few from gasoline barge loadings, and a great quantity of fuel was consumed, and combustion pollutants emitted, by simply heating large amounts of air. The combination of incineration and refrigeration was found thereby to be self defeating without a combustible gas blanket. Case III quantifies the value of this combination where relatively large vaporizations occur from cone roof tankage.

Net blanket gas expulsions from tankage for Case III are refrigerated from the same flexible diaphram gas holders as those in Case II. All hydrocarbons vaporized from crude oil and gasoline net breathing and working losses in cone roof tanks are condensed by refrigeration. Pilot gas is supplied from a more reliable source. Emissions from floating roof tanks in Case IIIA, however, are too few to be worth refrigerating.
The basic difference between this case and Case II regarding tankage vapor control, therefore, is only the return of tankage vapor losses to terminal through-puts for the cone roof tanks in the primary Case III. Case IIIA is the same as Case IIA regarding tankage vapor control.

Controlled emissions versus uncontrolled Base Case emissions in short tons per year and installed vapor control costs are:

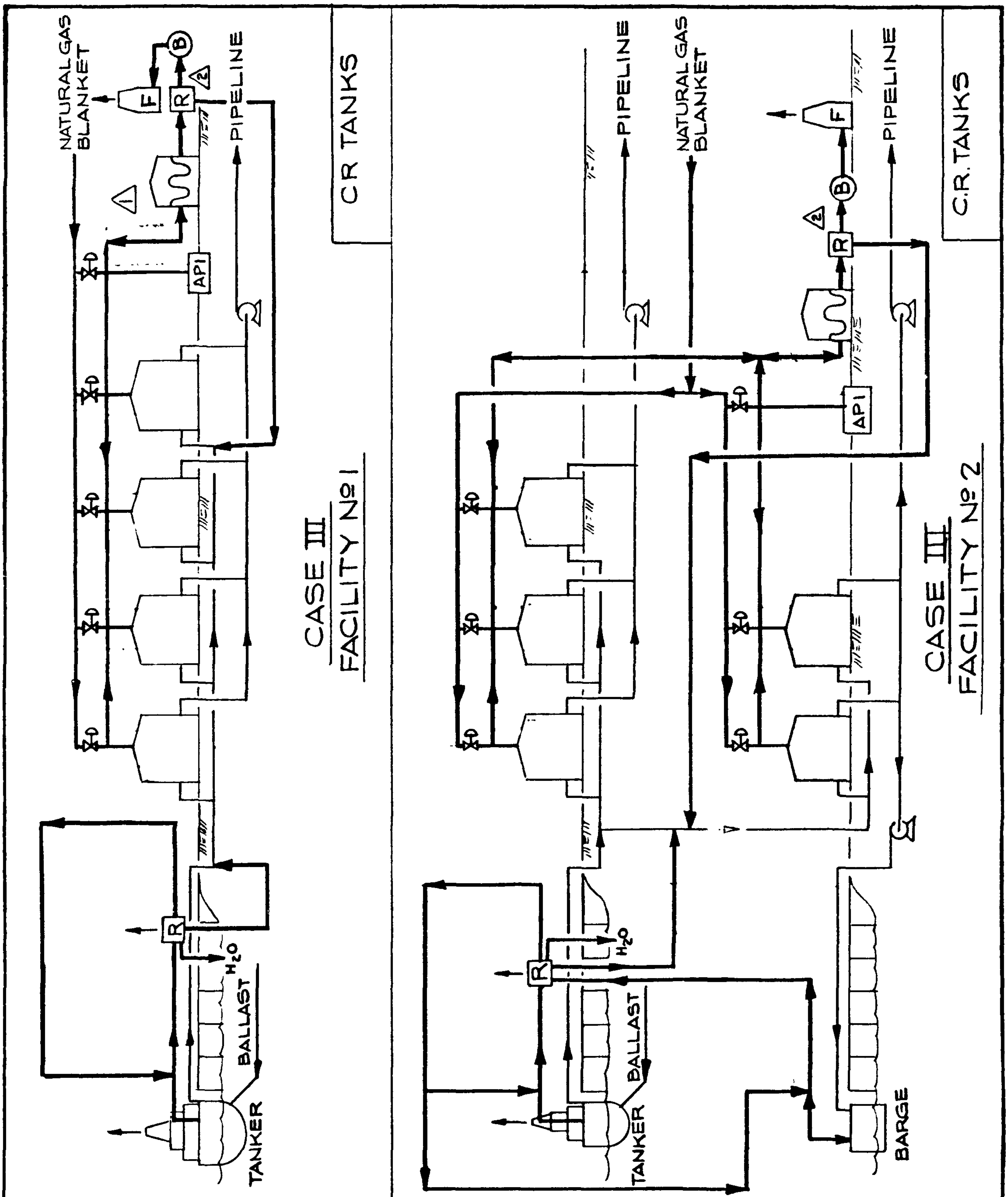
	EMISSIONS ST/Y					COST
Facility No. 1	H-C	NO_x	SO_x	CO	Part.	$ M
Base Case	2890	148	111	40	11	-
Case III	341	195	114	47	18	15,950
Case IIIA	340	216	111	50	21	13,220
Facility No. 2						
Base Case	2578	280	20	136	0	-
Case III	160	305	21	139	3.8	7,510
Case IIIA	159	332	20	143	7.9	4,510

Cases II and III have avoided the cost of significant blanket gas storages at the expense of consuming larger amounts of commercial natural gas. Gas demands for these cases in MSCFD are:

	Facility No. 1	Facility No. 2
Case II	2,723	1,347
IIA	3,613	2,573
Case III	2,163	1,156
IIIA	3,062	2,382

These huge commercial gas costs are reflected in Tables 1 and 2. Refrigeration electrical costs obscure the relationships somewhat in Case III. Here, in an effort to recover essentially all cone roof hydrocarbon emissions, refrigeration to $-170^{\circ}F$ has been estimated. Reliable availability of the above commercial gas supplies would greatly limit, if not inhibit, the application of these control systems.

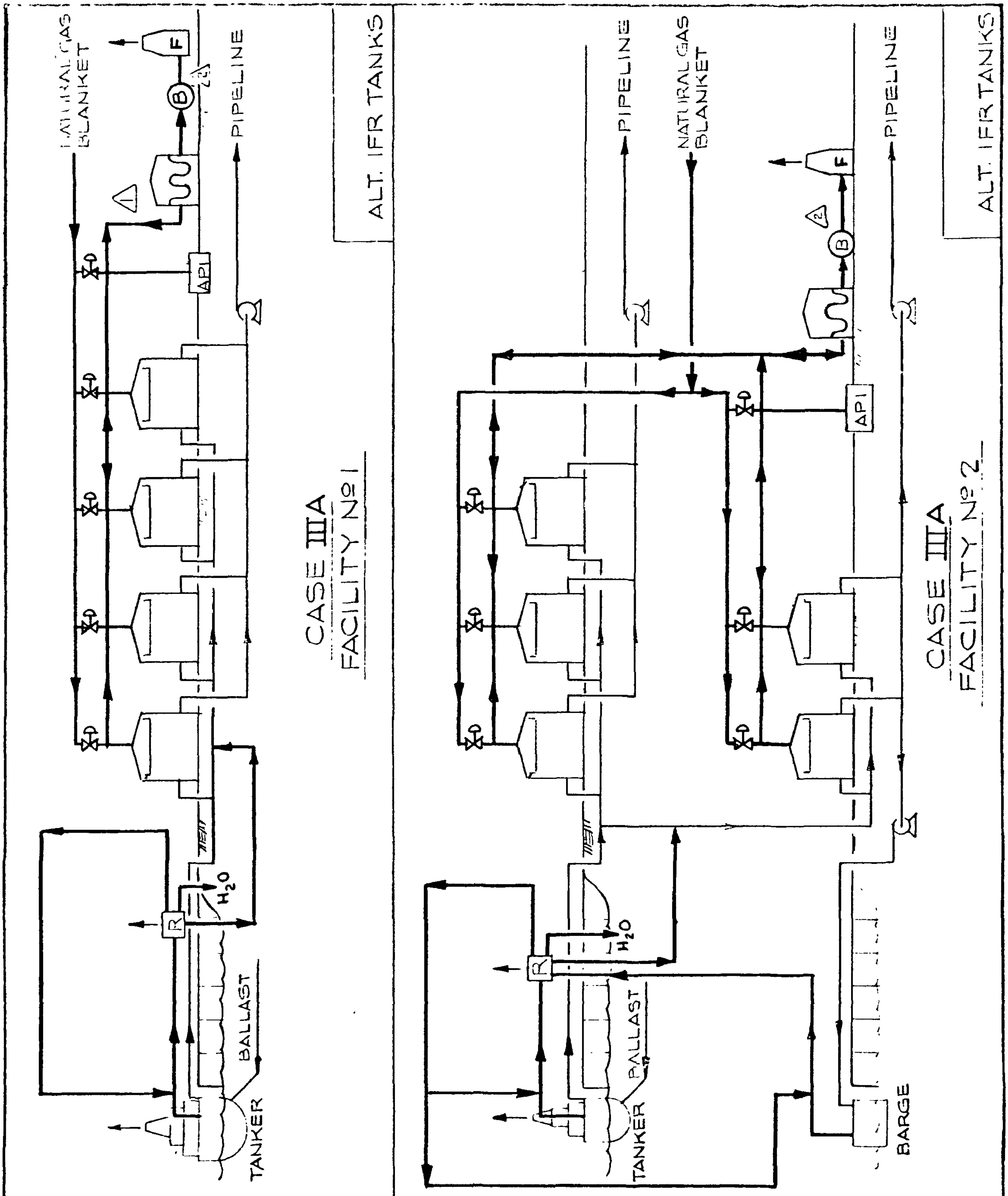
Crudes with sour vapors would cause the release of H_2S to atmosphere from refrigeration units handling ballast emissions, as in Case I, and they would cause the release of SO_x from incinerators handling tankage emissions.



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	REMOVED BLOWER			
2	1-13-78	ADD SECOND REFRIGERATER			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA			DRAWING NUMBER	REV.
	CUSTOMER	Environmental Protection Agency	153-1-8	2
	PLANT	Contract #68-02-2838		
	LOCATION	Case III Flow		

KLINGLER VELLUM 1021-8



ISSUE	DATE	REVISION	BY	CK	APPVD
1	12-14-77	REMOVED BLOWER			
2	1-13-78	ADD [illegible]			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA			DRAWING NUMBER	REV
	CUSTOMER	Environmental Protection Agency	153-1-8A	3
	PLANT	Contract #68-02-2838		
	LOCATION	Case IIIA Flow		

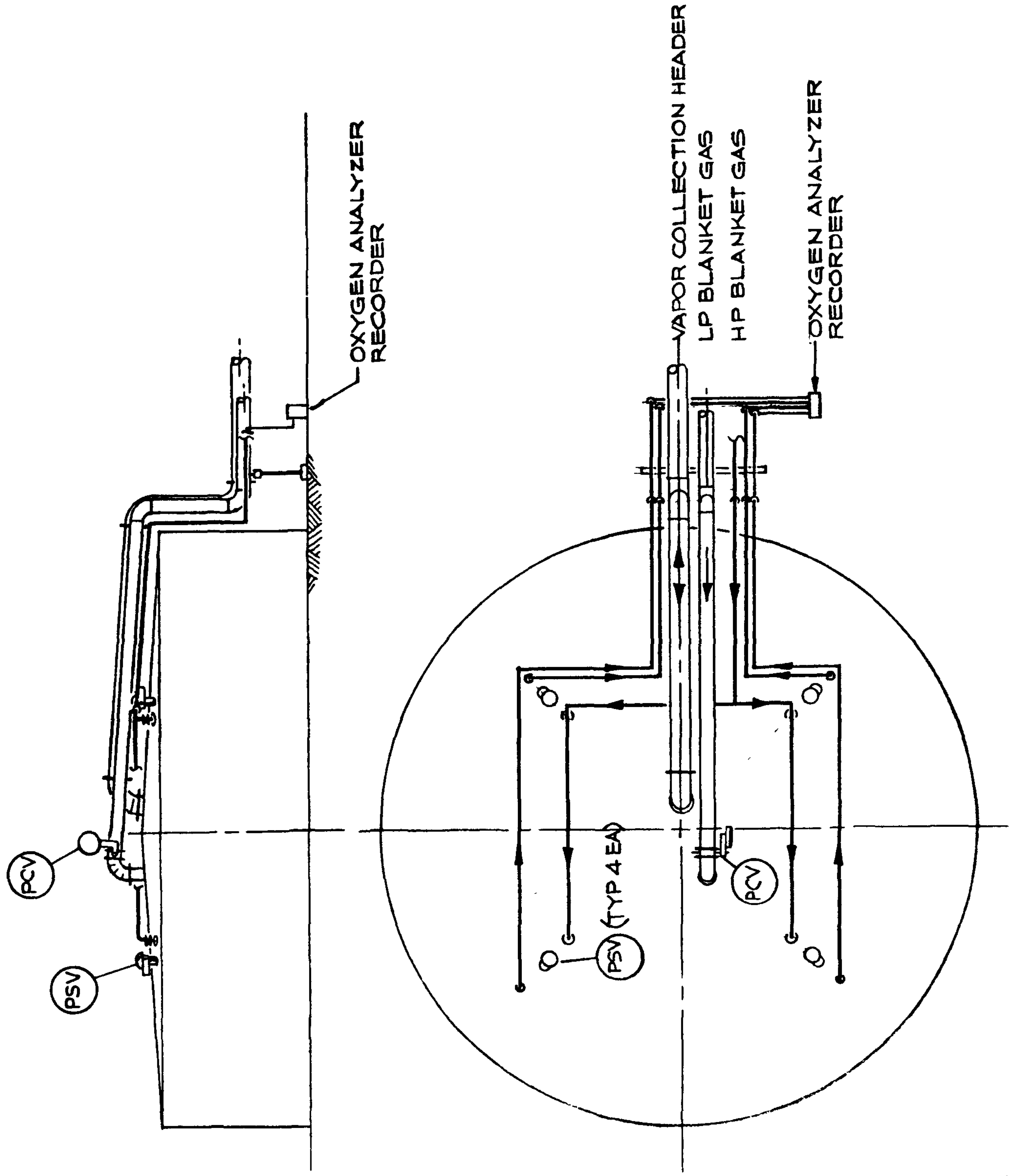
KLINGLER VELLUM 1021-8

5.6 CASE IV

This case differs from previous cases by storing and recycling blanket natural gas to tankage needs, instead of to flare, at the expense of conventional low-pressure gas storage facilities. Condensed hydrocarbons are returned from the treating process by refrigeration where cone roof tankage is used, and by simple compression where internal floating roof tankage is used. In both cases these net gas expulsions are compressed to pipeline pressures in order to economically condense tankage vaporizations, and are normally recycled back to blanket gas storage for power recovery. Marine emissions are treated by refrigeration as in Case I.

This case has been charged with the cost of floating roof gas storage and associated blanket gas distribution piping necessary to provide blanket gas for 1 1/2 days of maximum daily pumpout rates without a tanker being unloaded. Gas holder volumes amount to about 13% of the total cone roof terminal volumes and 18% of the total internal floating roof terminal volumes, the latter requiring higher blanket gas demands. With proper inventory management, large amounts of blanket gas purchases should only be limited to occasional storage tank turn-around operations, and this can be minimized by purging the tank with water fillings. Annual replenishment charges have been arbitrarily assumed to average that required for 1 1/2 major storage tank fills per terminal, however. Other fresh make-up blanket gas is eventually returned to sales in a reasonably scheduled and treated manner, and other direct operating costs, therefore, cancel out after the initial charge is capitalized. Refer to drawings 153-1-9 and 9A for this application to both facilities. Net blanket gas expulsions from tankage are transferred from small flexible diaphram surge tanks by the same blower arrangement as in Case II, but into floating roof gas holders at 7.0 osi pressure instead of into a water-sealed flare. Four such gas holders are needed for Facility No. 1 and two for Facility No. 2. Separate distribution piping and PCV's are needed to recycle this gas from these gas holders to storage tanks for blanketing before natural gas make-up is used. Drawing 153-1-23 illustrates a typical piping arrangement where a separate high and low (recycle) pressure supply source provides blanket gas to tankage. One oxygen analyzer sequentially records O_2 concentrations near each pressure-vacuum relief valve. An alarm is sounded at a central control location whenever excessive oxygen concentrations are reached. Refer to Table 3 paragraph 9.1.1 for pressure control valve settings.

Only when all floating roof gas holders and flexible diaphram receiving holders are full, or when operating schedules demand, is blanket gas from storage tankage returned to sales. A standby flare has been estimated for disposing of excess blanket gas when operations cannot be accommodated by sales. Normally the treated blanket gas is returned to gas storage and compression power is largely recovered. Treating the gas removes any accumulation of inorganic sulfur compounds, of water vapor, and of hydrocarbon vaporizations from tankage. The gas product is compressed to a pipeline pressure of 350 psig in order to accommodate the latter, and it is, thereby, suitable for returning to commercial gas. Commingling this treated gas with commercial natural gas supplies should cause no problems in heating value or flame control since essentially all of it was commercial gas to begin with. Air-propane blending for Btu control is not considered necessary. Two treating systems have been rated and estimated, one for condensing larger amounts of vaporizations from cone roof tankage



ISSUE	NO	DATE	REVISION	BY	CR	APPVD	ISSUE	NO	DATE	REVISION	BY	CR	APPVD

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract #68-02-2838	153-1-23	0
	LOCATION	Blanket Gas Piping		

KLINGLER VELLUM 1021-8

in Case IV and another for condensing smaller amounts from internal floating roof tankage in Case IVA. These have been considered for comparable reasons and do not necessarily constitute an optimum design application. Refer to drawings 153-1-21A and -21B. Treating facilities consist of a sponge iron guard chamber for the removal of stray inorganic sulfur compounds at 75 psig. Water removal is then accomplished by indirect refrigeration to 10^{o}F at 350 psig or glycol absorption at 90^{o}F and 350 psig. Refrigeration is also used where larger amounts of hydrocarbons are to be removed, such as emissions from cone roof tanks. Only moderate cooling has been estimated for relatively small standing losses from internal floating roof tanks. Both refrigeration and glycol treating are basically provided to reduce dew points to 10^{o}F in the event that blanket gas is returned to sales. Hydrocarbons condensed either by sea water in shell and tube exchanges, or by refrigeration, are returned to terminal throughputs. Returning condensed hydrocarbons is thereby incidental to the need for returning pipeline quality gas. The disadvantage of hydrocarbon build-ups to saturation levels in a combustible blanket gas media is in the collection and disposition of random condensations whenever temperature drops occur.

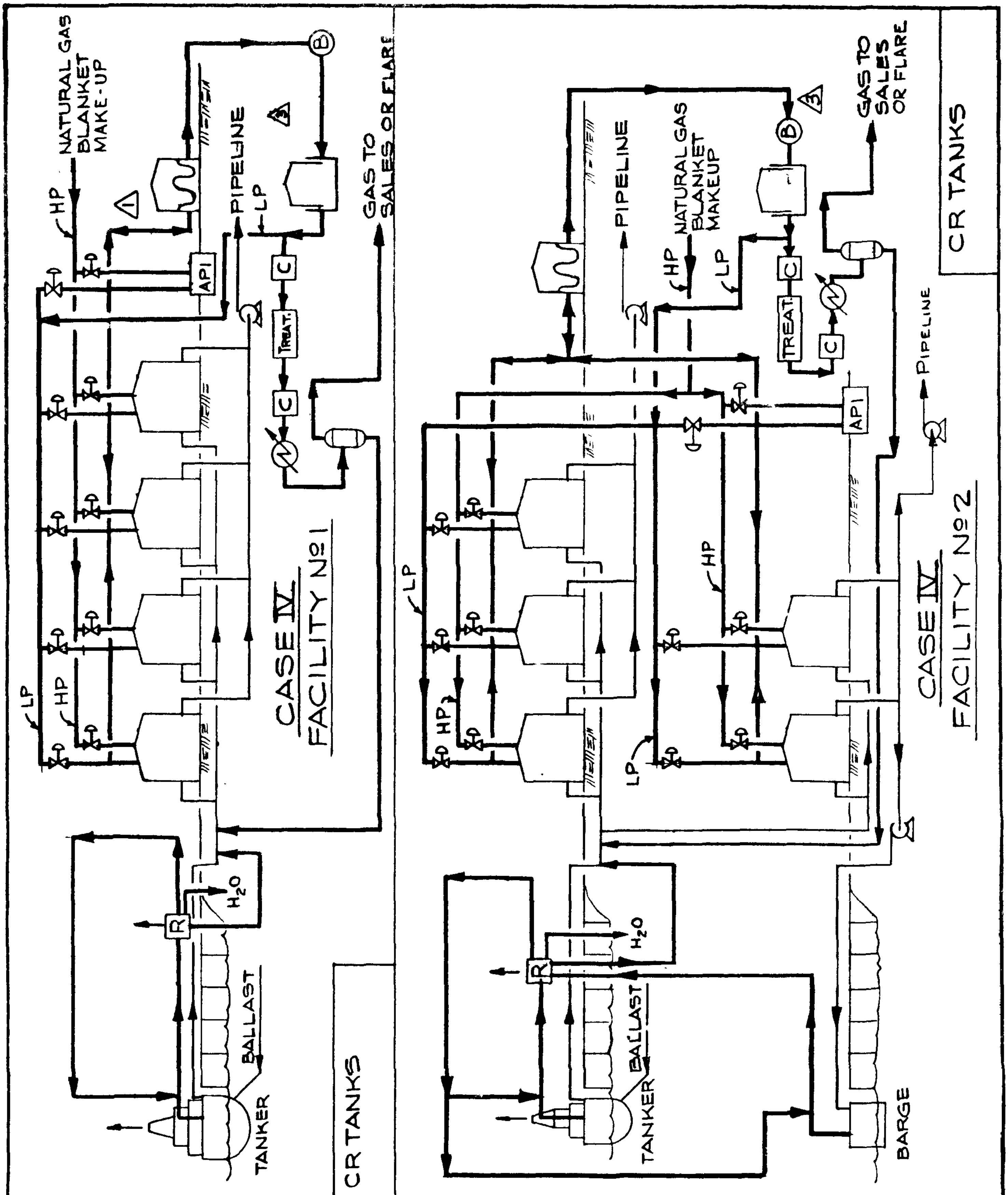
Controlled emissions versus uncontrolled Base Case emissions in short tons per year and installed vapor control costs are:

	EMISSIONS ST/Y					COST
Facility No. 1	H-C	NO_x	SO_x	CO	Part.	$ M
Base Case	2890	148	111	40	11	-
Case IV	344	148	111	40	11	34,300
Case IVA	339	149	111	40	11	50,530

Facility No. 2.	H-C	NO_x	SO_x	CO	Part.	\$ M
Base Case	2578	280	20	136	0	-
Case IV	164	280	20	136	0	13,350
Case IVA	160	281	20	136	0.1	18,530

Although lower operating costs result in Case IVA, the added cost over Case IV for internal floating pans lessens that control system's overall cost effectiveness. Also, the benefits of almost total hydrocarbon recovery to terminal throughputs is not sensitive to the cost effectiveness. Refer to Tables 1 and 2 for related economic values.

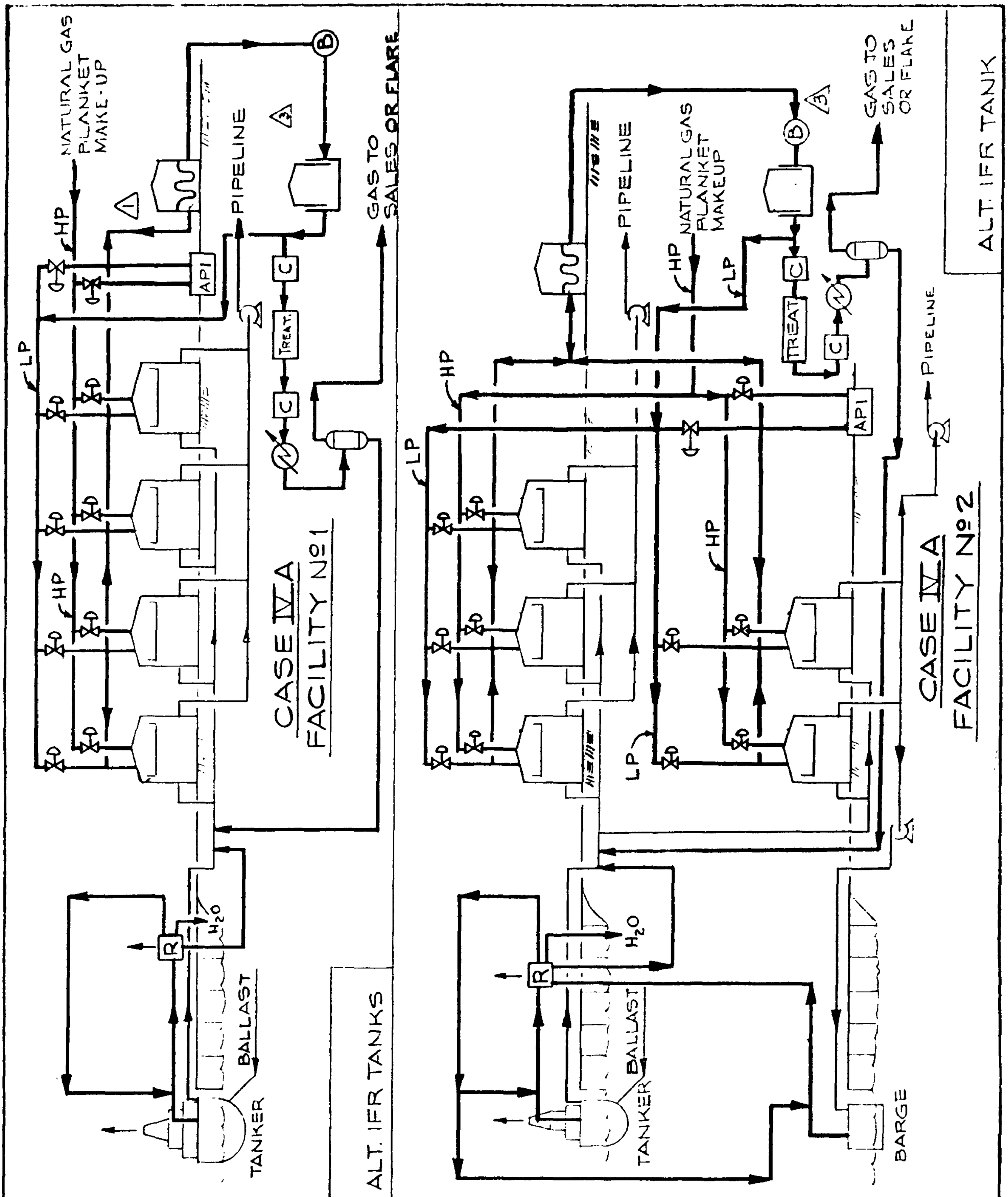
Crudes with sour vapors would cause the release of H_2S to atmosphere from refrigeration units handling ballast emissions as in Case I. They would also cause more frequent replacement of sponge iron in the guard chambers of treater units. Very sour crudes may render sponge iron less practical than a conventional sulfur removal (Claus) plant. Guard chambers have been sized and estimated for two changes per year with 25 ppm of H_2S in the feed stream. Refer to paragraph 9.2.10.



ISSUE NO	DATE	REVISION	BY	CK	APPVD	ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-17-77	REMOVED BLOWER				3	1-11-77	REVISED TREATING UNIT			
2	12-27-77	ADDED ABSORBER									

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV.
CUSTOMER	Environmental Protection Agency	153-1-9	3
PLANT	Contract #68-02-2838		
LOCATION	Case IV Flow		

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-17-77	REMOVED BLOWER			
2	12-21-77	ADDED ABSORBER			
3	1-11-77	REVISED TREATING UNIT			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract #68-02-2838	153-1-9A	3
	LOCATION	Case IVA Flow		

KLINGLER VELLUM 1C21-8

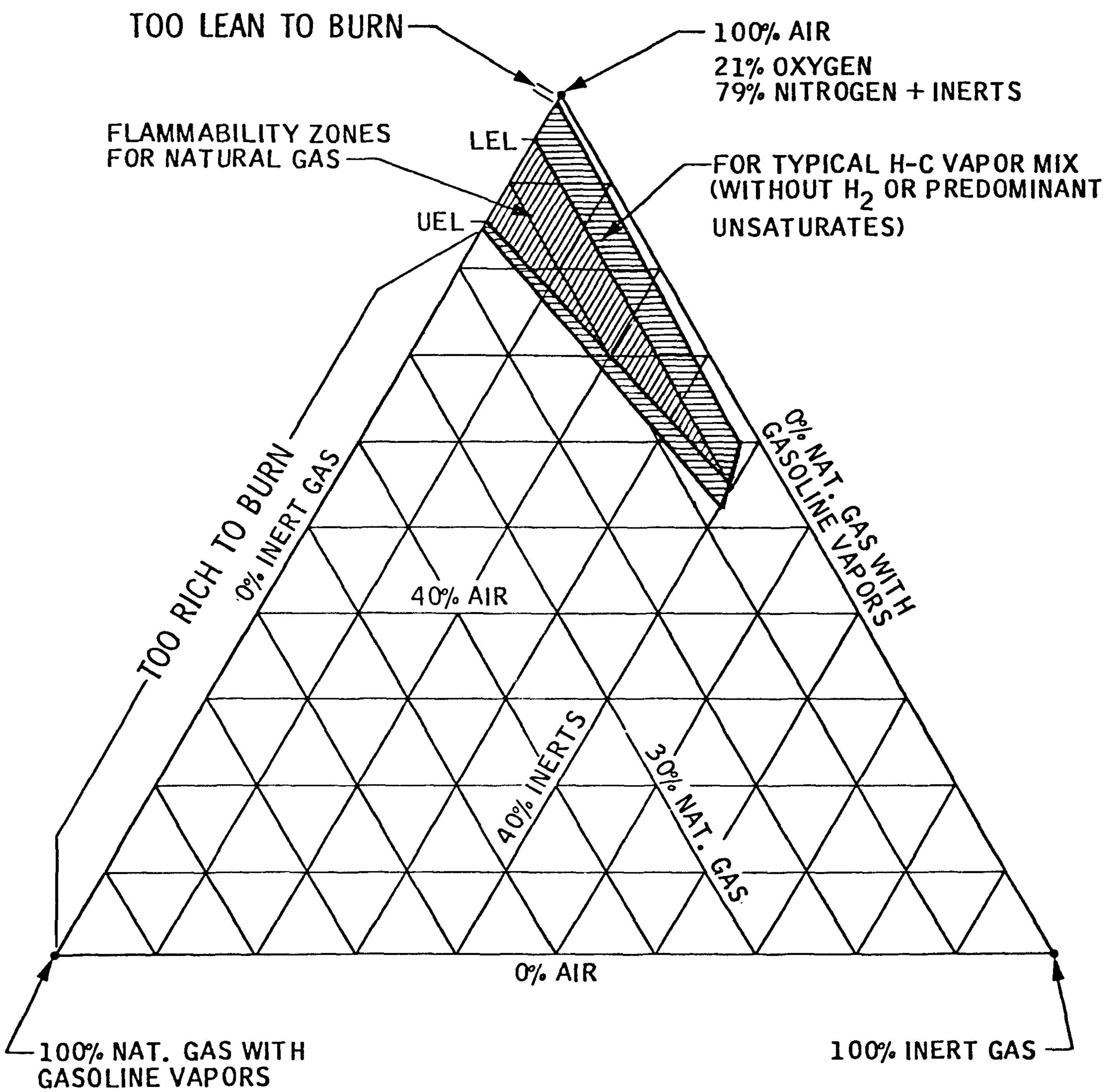
5.7 CASE V

Case V differs from Case IV by being totally enclosed and by returning vapors displaced from tankage by ship unloadings back to the ship. Vapors displaced by barge lcadings are similarly returned back to tankage. In other words, this is a balanced displacement vapor control syscem between marine vessels and shore tankage. Uncondensed vapors from refrigerated ship ballast emissions and from gasoline barge loading emissions are collectively transferred by blowers to floating roof blanket gas holders on the basis that these marine vessels have arrived inerted with natural gas. Although it would rarely occur, net excess blanket natural gas could be returned to sales when all blanket tankage is full, or as dictated by schedules. Blanket gas, however, is normally shipped away in tankers, and treating units have much less importance in this case than they do in Case IV. Refer to drawings 153-1-10 and 10A for this application to both facilities, and to Tables 1 and 2 for related economic values.

Of importance here is that only breathing and working loss emissions are received by flexible diaphram gas holders in Case V, and only standing loss emissions from tankage with internal floating roofs in Case VA. These emission losses in the latter case are very small, and the collection piping and vapor storage from tankage is relatively very small. The only significant amount of vapor expelled into floating roof gas holders is that from ship ballasting operations at berth. Since the enclosed volume of this system is reduced by ballast water displacements, these rates comprise the design capacity of blanket gases treated and returned to sales. Treating units are the same in principal as those in Case IV, including a standby flare in the event that sales cannot accommodate operating schedules. Refer to drawings 153-1-21A and -21B and paragraph 9 .2.10.

A restriction to this relatively effective, totally enclosed, vapor control system is that ships and barges using either of these two terminal facilities must be blanketed with natural gas, which is thereby removed by ships unloading into the terminals. This gas should be utilized wherever crude or gasoline is loaded onto the ships. If ballast is taken into cargo compartments at sea, some compression, containment, and ultimate burning of the gas displaced would be more desirable than exhausting it to atmosphere. Associated retrofitting expenses have not been estimated. In unit heating values, the import/export ratio of crude entering to equal volumes of gas leaving at atmospheric pressure amounts to 1100 to 1. Regarding tanker safety, it takes more air to explode a tanker of fuel gas and hydrocarbon vapors than one inerted with flue gas. As a matter of fact, the more flue gas there is with the hydrocarbon vapors (up to about 98 vol %) the less air is required for combustion[6], as shown on Drawing No. 153-1-25.[7] However, empty tankers with natural gas contain more combustible volume than those with flue gas or air in their ullages, and for this reason require special considerations which are outside the scope of this effort.

In order to provide more operating pressure drop flexibility in this balanced displacement system, and margin of safety away from storage tank relief valve pressure settings, the cost of 1/2" thick fixed tank roofs has been added to this case, instead of the conventional 3/16" thick roof, and duct sizes have been reduced accordingly. Thus, tank roofs are more in line with ship cargo compartment thicknesses and pressure levels [4,8]. Refer to drawings 153-1-19A and -20A. A further safety measure to prevent vacuum reliefs from opening on ship compartments is a 60 psig natural gas repressuring header and hoses to ships that admits gas on pressure

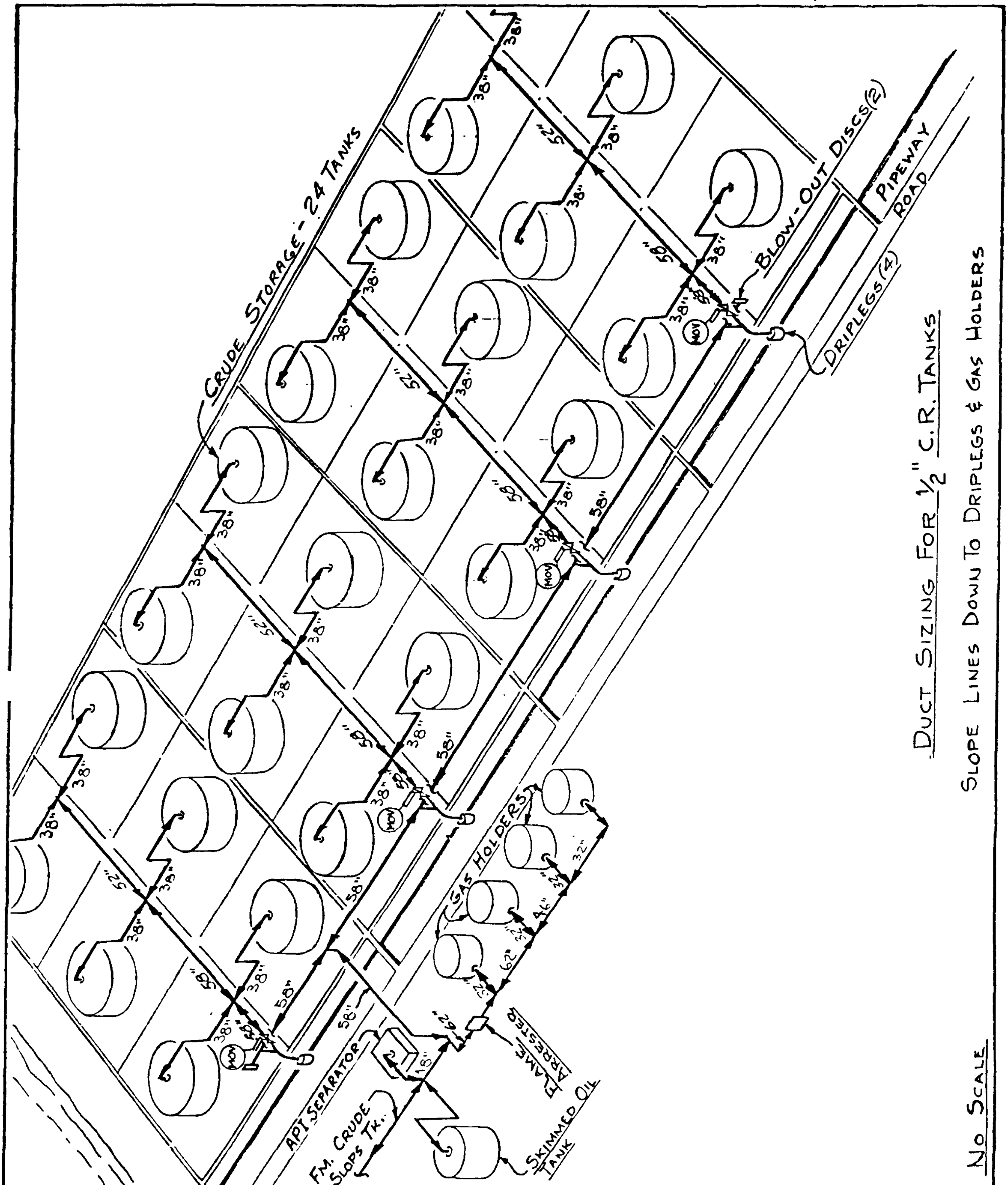


% ARE BY VOLUME AT
APPROXIMATE STANDARD
CONDITIONS.

LEL = LOWER EXPLOSIVE LIMIT
UEL = UPPER EXPLOSIVE LIMIT

ISSUE	NO	DATE	REVISION	BY	CK	APPVD	ISSUE	NO	DATE	REVISION	BY	CK	APPVD

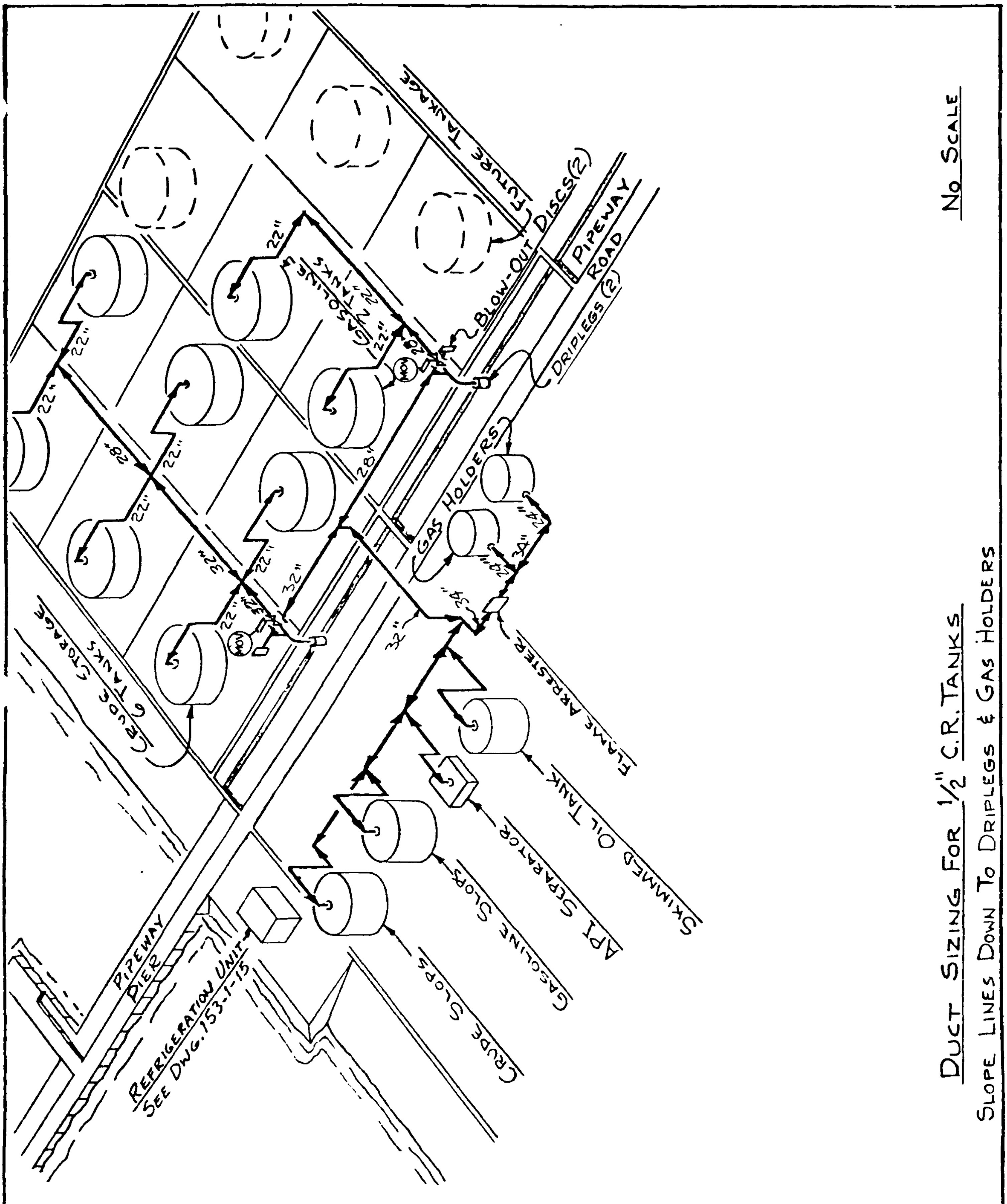
ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER PLANT LOCATION	DRAWING NUMBER 153-1-25	REV. 0



ISSUE	NO	DATE	REVISION	BY	CK	APPVD
	1	3-7-78	ADDED MOV --	TS		

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER Environmental Protection Agency PLANT Contract No. 68-02-2838 LOCATION Facility #1, Vapor Collection Layout	DRAWING NUMBER 153-I-19	REV. 1

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APPVD	ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	3-7-78	ADDED MOV	TS								

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract No. 68-02-2838	153-1-20	1
	LOCATION	Facility #2 Vapor Collection Layout		

KLINGLER VELLUM 1021-8

control to compartments before vacuum relief valves open. Piping costs have been added to Case V, and retrofitting costs have been estimated.

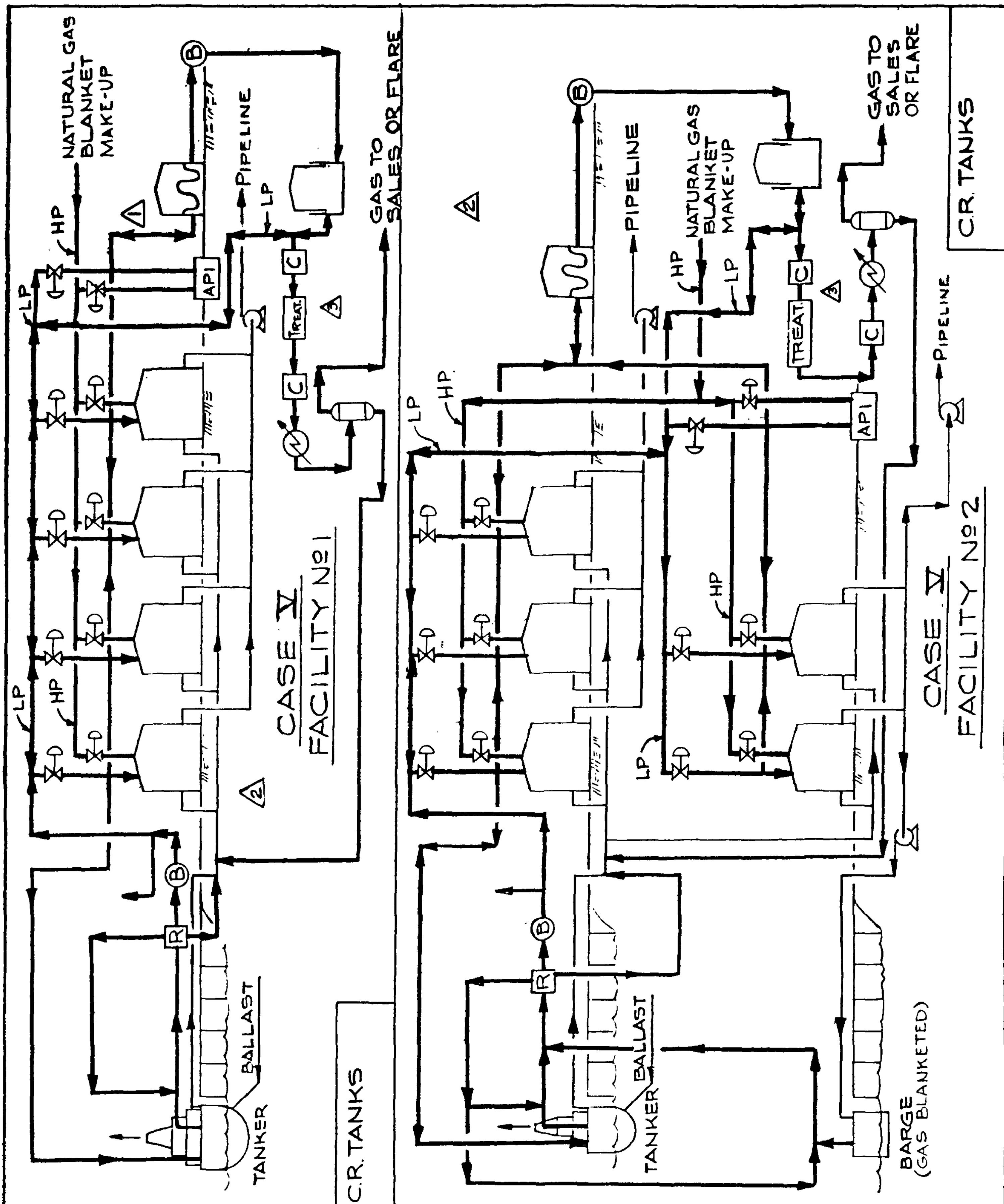
Since gas holder capacities have been predicated upon supplying 1½ days of pipeline pumpout displacements in each terminal, gas holders in this case are as large as those in Case IV. Low and high pressure blanket gas distribution systems are also similar to Case IV. Refer to drawing 153-1-23 for typical piping layouts and Table 3, paragraph 9.1.1, for blanket gas control pressure settings.

Controlled versus uncontrolled Base Case emissions in short tons/year and installed vapor control costs are:

	EMISSIONS ST/Y					COSTS
	H-C	NO_x	SO_x	CO	Part.	$M
Facility No. 1						
Base Case	2890	148	111	40	11	-
Case V	85	148	111	40	11	40,160
Case VA	80	148	111	40	11	56,140
Facility No. 2						
Base Case	2578	280	20	136	0	-
Case V	67	280	20	136	0	14,750
Case VA	63	280	20	136	0	19,960

The cost effectiveness of this control system is comparable to other systems which have large blanket gas storages. However, it has been assumed therein that the value of the commercial gas received balances off that which is delivered to the terminal where the tankers receive their crude oil or gasoline cargoes. Likewise, no credit has been provided for the gas received from barges. Although treating units would seldomly be used, they have been estimated to cost as much as those in Case IV, but direct operating costs and secondary emissions have been reduced from a 90% loading factor in Case IV to a 10% factor in Case V. Because of the close coordination needed between vessel personnel, the wharfinger, and shore tankage operations with this vapor-balancing system, two full-time operations personnel have been added to the direct operating costs of this case for both facilities.

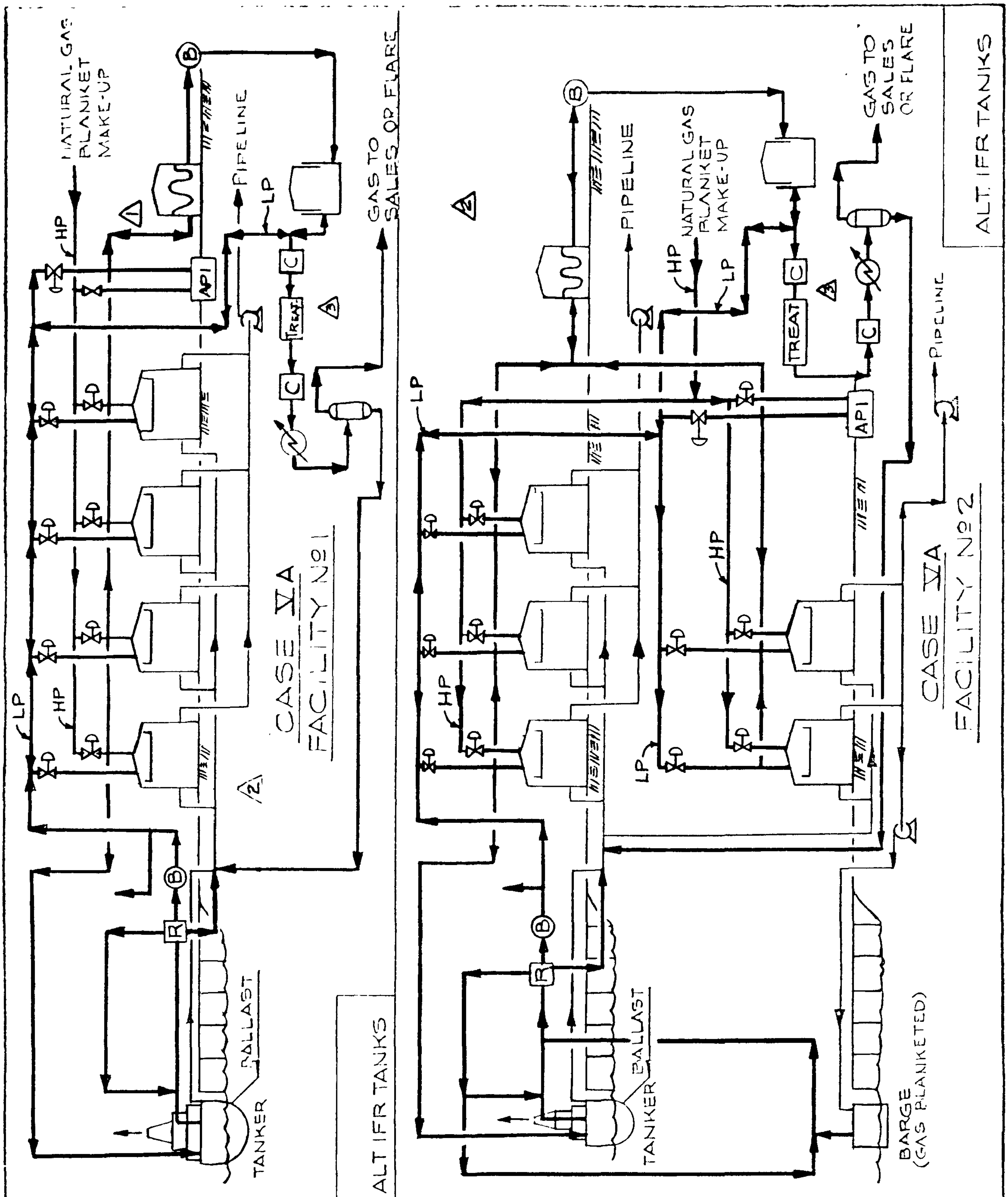
No sulfur emissions would be caused by adding sour crude vapors to this totally enclosed vapor control system. Crudes with sour vapors, however, would increase the frequency of spent sponge iron disposals and fresh sponge iron replacements in treating unit guard chambers. Except to the extent that sulfur is removed in the treating units of Facilities No. 1 and No. 2, SO_x would be emitted from the combustion of such exported sour gases elsewhere.



ISSUE NO	DATE	REVISION	BY	CK	APPVD	ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	REMOVED BLOWER				3	1/13/78	REVISED TREATING UNIT			
2	12-27-77	BALLAST DISPL. TO TREAT									

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV.
CUSTOMER	Environmental Protection Agency	153-1-10	3
PLANT	Contract #68-02-2838		
LOCATION	Case V Flow		

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	REMOVED BLOWER			
2	12-21-77	BALLAST DISPL. TO TREAT			
3	1/13/78	REVISED TREATING UNIT			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV
CUSTOMER	Environmental Protection Agency	153-1-10A	3
PLANT	Contract #68-02-2838		
LOCATION	Case VA Flow		

KLINGLER VELLUM 1021-8

5.8 CASE VI

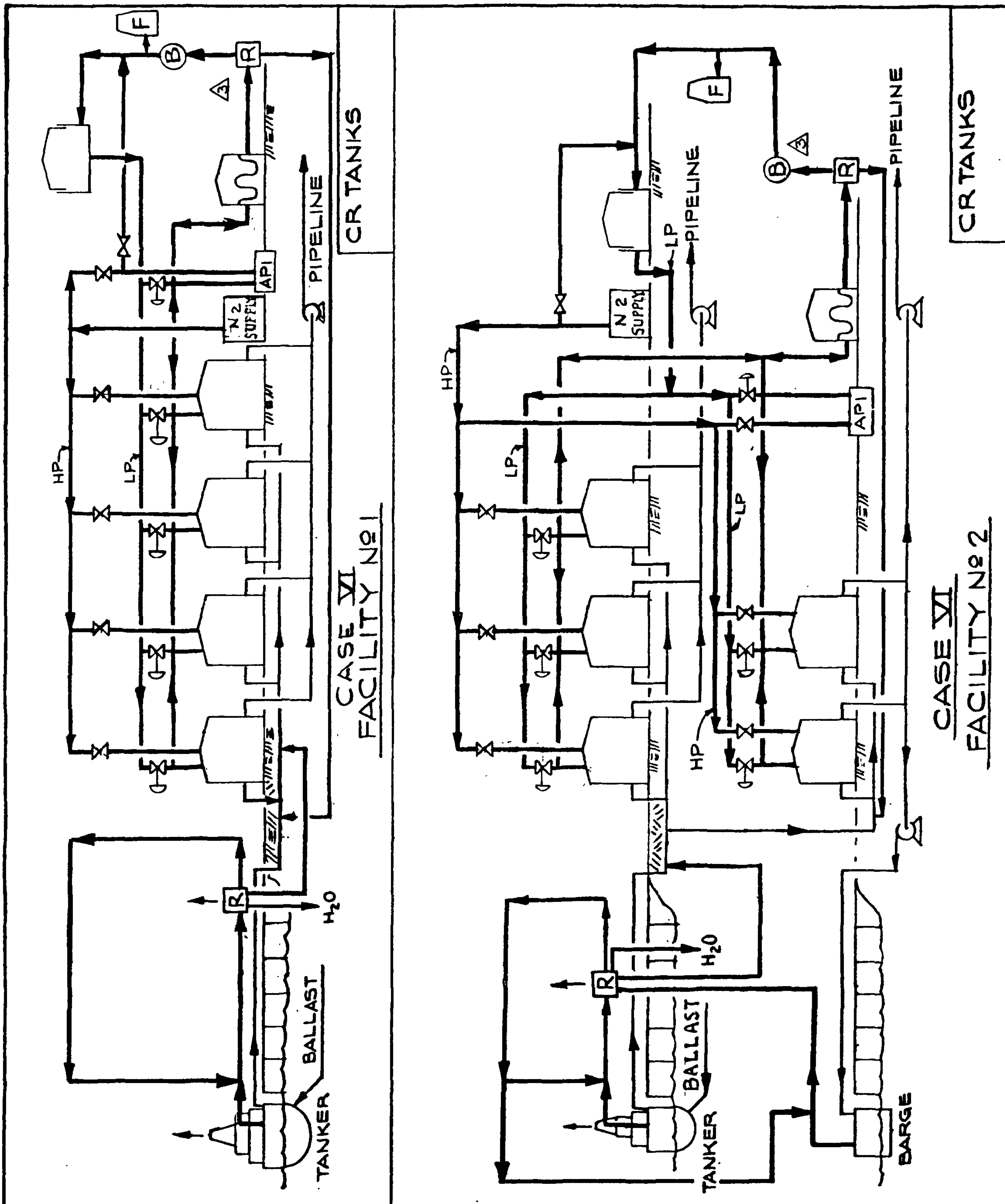
This case compares with Case IV but utilizes nitrogen for gas blanketing tankage instead of natural gas. Since this study basically assumes relatively sweet crude vapors, no attempt is made in this case to chemically remove sulfurous gases. The intent here is that the containment, less normal blanket gas secondary emissions, will not accummulate contaminating, corrosive, or other detrimental ingredients. Excess blanket gas from cone roof tankage is refrigerated to recover hydrocarbons and incinerated in this case. That from internal floating roof tankage is directly incinerated, since about 99% of cone roof emissions are restrained by internal floating roofs. Marine emissions are handled as they are in Case I. Refer to drawings 153-1-11 and 11A for this application to both facilities, and to Tables 1 and 2 for relative economic values.

Nitrogen has been chosen for this case instead of carbon dioxide because water vapor condensations are less corrosive and the costs of the gases are about the same on a volume basis. Annual nitrogen replenishing charges have arbitrarily been assumed to average that required for 1 1/2 major storage tank fills per terminal. Nitrogen in these volumes is priced at $60 per ton delivered as liquid in the Los Angeles area. Leased equipment costs have been included.

Gas holder capacities are as large as those in Case IV and V. Only low pressure blanket gas distribution is provided from these holders, however, because of the heat demand for nitrogen make-up at pumpout displacement rates. Heat input, from leased ambient vaporizers, allows up to 100,000 SCFH of nitrogen from a leased liquid storage tank. This make-up rate normally supplies gas holders. If unsafe oxygen levels are detected by storage tank oxygen analyzer-recorders, however, (see drawing 153-1-23, para. 5.6) a small high-pressure nitrogen distribution line is used to purge the tank to safe oxygen levels. Alarms are set at large margins of safety below the upper explosive limit. Nitrogen purges are automatic with alarms to notify personnel of maloperating conditions. Valves do not automatically admit high pressure nitrogen blanket gas on pressure control.

Controlled versus uncontrolled Base Case emissions in short tons per year and installed vapor control casts are:

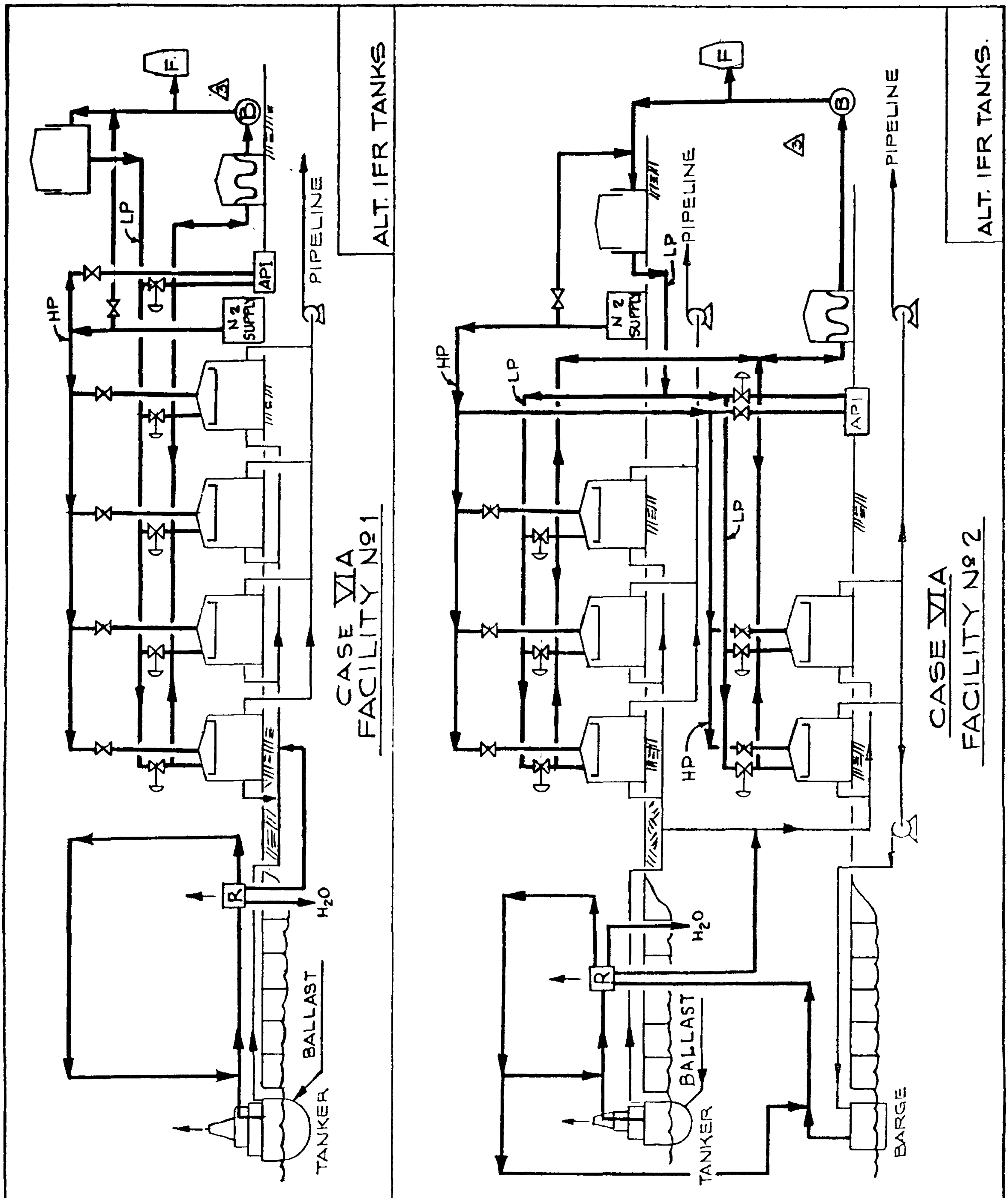
	EMISSIONS ST/Y					COSTS
	H-C	NO_x	SO_x	CO	Part.	$M
<u>Facility No. 1</u>						
Base Case	2890	148	111	40	11	-
Case VI	323	148	111	40	11	42,190
Case VIA	320	148	111	40	11	50,090
<u>Facility No. 2</u>						
Base Case	2578	280	20	136	0	-
Case VI	155	280	20	136	0	14,200
Case VIA	153	280	20	136	0	18,390



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	ISOL. INCIN. ADDED ADSORP.			
2	12-27-77	REMOVED TANKER INERTING			
3	1/14/78	ADDED REFRIGERATERS			
4	1/21/78	REMOVED HP CONTROL VALVES ADDED FURNACES			

			DRAWING NUMBER	REV.
ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	153-1-11	4
	PLANT	Contract #68-02-2838		
	LOCATION	Case VI Flow		

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APP'VD
1	12-14-77	ISSUED [illegible] ADDED ABSORP.			
2	12-27-77	REMOVED TANKER [illegible]			
3	1-16-78	ADDED REFRIGERATORS			
4	2-27-78	REMOVED HP CONTROL VALVES			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA		DRAWING NUMBER	REV.
CUSTOMER	Environmental Protection Agency	153-1-11A	4
PLANT	Contract #68-02-2838		
LOCATION	Case VIA Flow		

KLINGLER VELLUM 1021 B

5.9 CASE VII

This case, like Case V, is a balanced displacement system between marine vessels and shore tankage, but it utilizes flue gas as a blanket gas media instead of natural gas. Purchased nitrogen is not used in this case, as it is in Case VI, because tankers would be removing it from the terminals in volumes equal to daily terminal tanker throughputs. Tankers utilizing terminals in this case are assumed to already have stack inerting systems, and barges are assumed to be flue gas blanketed. If such were not the case, however, special accommodations, which have not been estimated, could be provided. Make-up flue gas is taken from ship stack gases at berth following their on-board sea water scrubbing operations. Dock-side turbo-blowers deliver this stack gas at 1 psig to on-shore floating roof gas holders, the sizes of which are the same as those for Cases IV, V and VI. Blanket gas from shore side tankage is displaced into the tanker while it is unloading, so that instead of the tanker normally filling its own cargo compartments with flue gas, it is filling the gas holder on shore with displaced vapors. Tanker inerting capacities are assumed to be at least 125% of their off-loading rate [8,9], although these capacities are more than ample for supplying either terminal facility because each tanker leaves 20% ballasted. Also barges in Facility No. 2 import blanketing flue gas. If flue gas make-up is needed over that which is available from ships at berth, on-shore inert gas generators are available. These generators exchange their hot flue gas heat with sea water in coolers to about an 80^{o}F dew point, which is approximately the dew point received from ships' scrubbers [9]. Gas holder storages provide a blanket gas reservoir at 7.0 osi pressure. Only a low pressure blanket gas distribution system is available because of the low source pressure of flue gas. Refer to drawing 153-1-12 and 12A for this application to both facilities and to Tables 1 and 2 for related economic values.

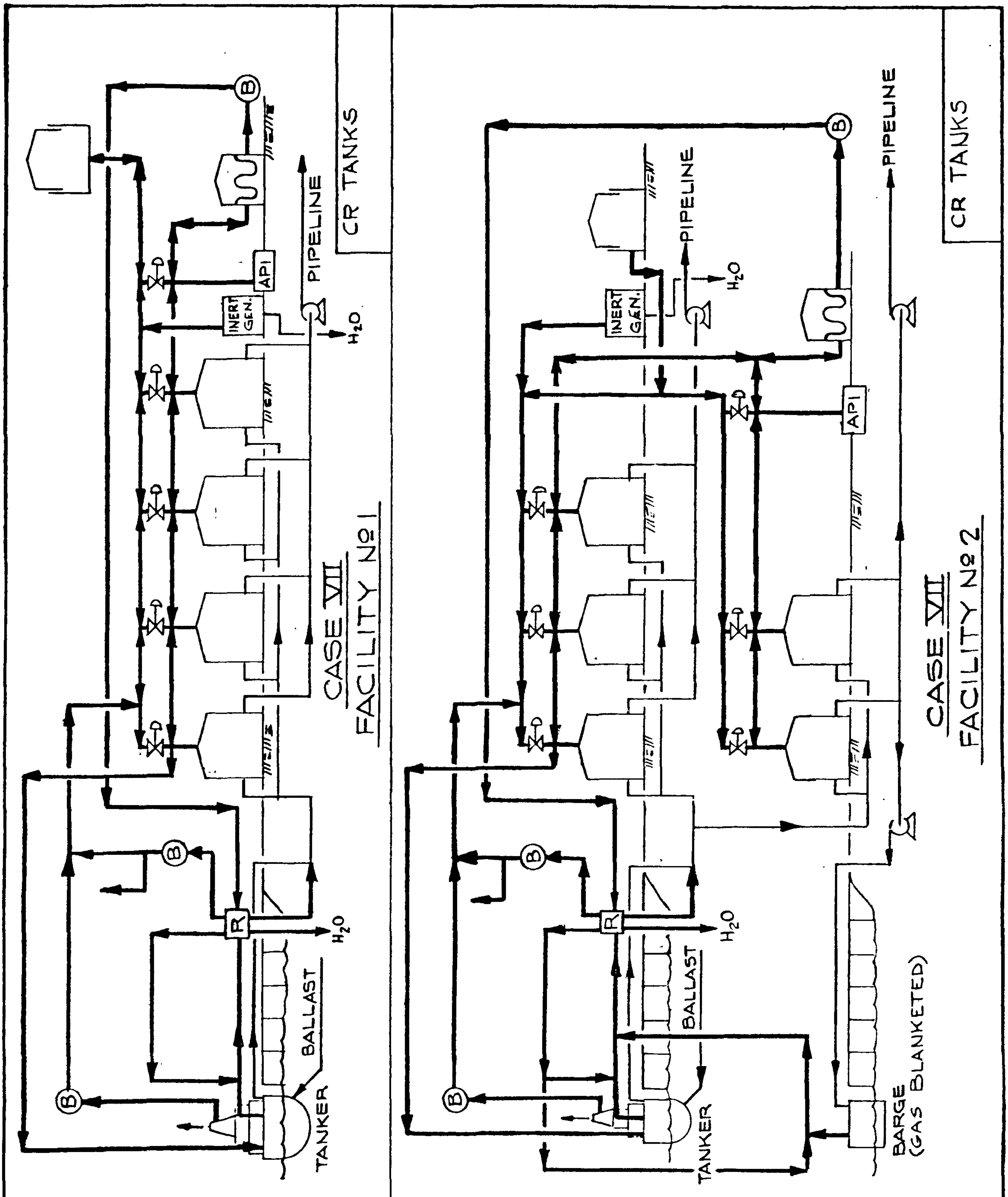
Costs have been added to this case for a 1/8" corrosion allowance on all interior surfaces exposed to the flue gas blanket, instead of an application of corrosion resistant paint, in keeping with the decisions at Valdez. Here, where scrubbed flue gas is also used as a blanketing media, it was concluded after some study that the cost of applying corrosion resistant print would be forstalled until such time that corrosion probles indicated its necessity[10]. Accordingly, the fixed roof tankage for both terminals in Case VII are 3/8" thick, 1/2" being provided to allow more operating pressure drop flexibility in this balanced displacement control system, as in Case V.

Controlled versus uncontrolled Base Case emissions in short tons per year for Case VII are:

	EMISSIONS ST/Y					COSTS
	H-C	NO_x	SO_x	CO	Part.	$M
Facility No. 1						
Base Case	2890	148	111	40	11	--
Case VII	59	164	123	44	12	47,130
Case VIIA	59	164	123	44	12	64,140
Facility No. 2						
Base Case	2578	280	20	136	0	--
Case VII	55	300	21	146	0	18,100
Case VIIA	55	300	21	146	0	23,800

Here as in Case V, two full-time operations personnel have been added to the direct operating costs at both terminals in order to assure close coordination with vessel personnel, the wharfinger, and shore tankage operations.

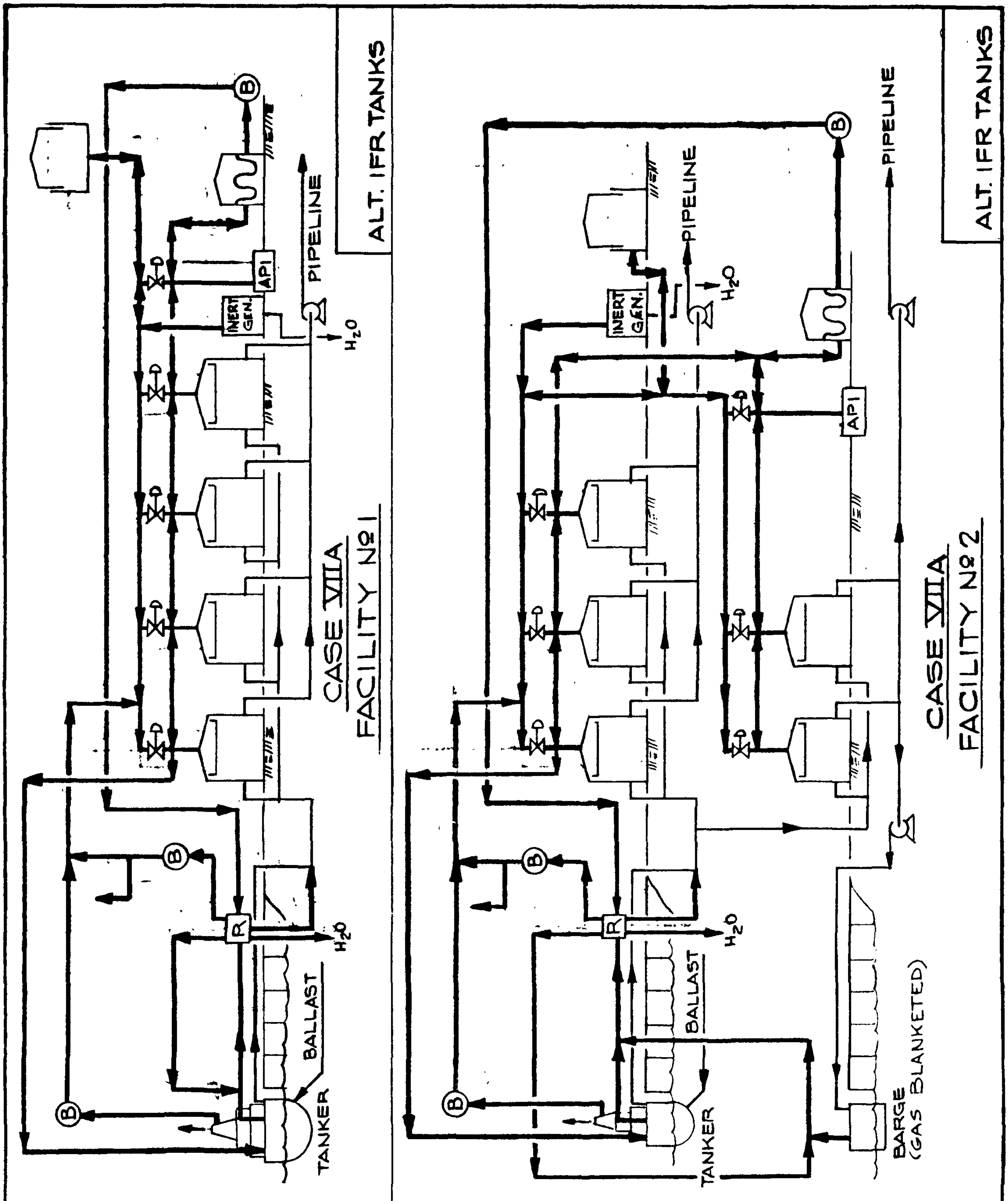
Stack emissions have increased due to the need to fire boilers for Facility No. 1 and diesels for Facility No. 2 from 10% to 90% loads during a few hours of non-pumping docking time daily, to supply on-shore blanket flue gas storages. Additional fuel costs have been assumed an operating contingency cost.



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	ISOL. INCIN. ADDED CAT. CONV			
2	12-27-77	ADDED BALLAST INCINERATER			
3	1/14/78	REVISED REFRIG. CONNS.			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA			DRAWING NUMBER	REV.
	CUSTOMER	Environmental Protection Agency	153-1-12	3
	PLANT	Contract #68-02-2838		
	LOCATION	Case VII Flow		

KLINGLER VELLUM 1021-8



ISSUE NO	DATE	REVISION	BY	CK	APPVD
1	12-14-77	ISOL. INCIN. ADDED CAT. CONN			
2	12-27-77	ADDED BALLAST INCINERATER			
3	1/14/78	REVISED REFRIG. CONNS.			

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA			DRAWING NUMBER	REV.
	CUSTOMER	Environmental Protection Agency	153-1-12	3
	PLANT	Contract #68-02-2838		
	LOCATION	Case VIIA Flow		

KLINGLER VELLUM 1021-8

6.0 VAPOR CONTROL ECONOMICS

The cost of each vapor control system has been estimated as an incremental cost to the total installed cost of new Base Case facilities. Vapor control systems have not been estimated, therefore, as being retrofitted to existing shore facilities. Engineering overheads and field indirect costs have been pro-rated to major vapor control equipment as applicable to the total terminal construction costs. All facility costs comply with fourth quarter 1977 or first quarter 1978 prices in the Los Angeles, Calif. area. Utility costs, however, apply to other areas as described below. Gas and electric power availability in the quantities needed for various vapor control systems is assumed to be reflected in their billing rates.

Marine vessel retrofitting costs per vessel have been estimated separately.

6.1 COST EFFECTIVENESS

Each vapor control system for each terminal facility, both with cone roof tanks and with internal floating roof tanks has been process rated and estimated for total installed cost and direct operating cost. Two separate sets of utility rates have been used. The cost of each system has been credited by those hydrocarbons the system returns to the terminal thru-put. Net annualized costs are divided by those hydrocarbon emissions recovered over base case emissions, less any secondary emissions. Secondary emissions are defined, herein, as those resulting from the vapor recovery system itself.

The cost effectiveness (CE) of each vapor collection system has been expressed as:

$$CE = \frac{ACC + DOC - CREDITS}{U - C} \quad \text{in dollars/ton}$$

where:

ACC (annualized capital charges) = total installed cost (TIC) difference times 0.1715 for capital recovery over a 15 year period, including 0.1315 for depreciation and interest and .04 for taxes, in \$/year.

DOC (direct operating costs) = operating and maintenance labor difference and utility costs for the system, in \$/year.

Credits = value of recovered hydrocarbons returned to the terminal throughput, in \$/year. Crude oil has been valued at \$10.95 per barrel with entitlements and gasoline has been valued at \$16.40 per barrel.

U = total hydrocarbon emissions in the Base (uncontrolled) Case in tons/year.

C = Hydrocarbon emissions that cannot be controlled in each terminal with a vapor collection (controlled) system, including secondary hydrocarbon emissions, in tons/year.

Retrofitting estimates for tankers and barges are not included with CE computations because the number of specific tanker and barge configurations servicing these two terminals has not been defined. Tables 1 and 2 summarize the cost-effectiveness of each alternative vapor recovery system, and their cost-effectiveness variables.

The use of segregated ballast in tankers would result in much less total terminal cost effectiveness than this study has shown, especially in the more costly cases. In cases IV, V, VI, and VII, for instance, the majority of capital costs are for tankage emission control. The rest, for ballasting or barge loading emissions, handles 75% of all the hydrocarbon emissions from Facility No. 1 and 89% of all those from Facility No. 2. Segregated ballast would eliminate the more cost effective ballast emission requirements.

Cost effectiveness values for marine and tankage vapor control systems vary from $1320 to $4010 per ton of hydrocarbon recovered in Facility No. 1 and from $699 to $1670 per ton of hydrocarbon recovered from Facility No. 2. The cause for this unapparent relationship (the larger facility being less cost effective) lies in the capital costs needed for handling massive gas quantities over relatively large areas in the larger facility, and in the gasoline tanker and barge operations which create large H-C emissions from the smaller facility. While hydrocarbons recovered from Facility No. 1 are about 2560 T/Y, those from Facility No. 2 are only 160 T/Y less, but costs vary from $11 to $69 million for Facility No. 1, compared to only $2 to $29 million for the smaller facility.

The cost effectiveness of large and small terminals having like operations should favor the larger terminal, but perhaps not to the extent that normal economics of scale prevail in processing plants. Capital investments for these vapor control cases are more sensitive to the lbs./hr. of product handled, (low pressure hydrocarbon vapor) than are processing plants of their liquid products.

6.2 TOTAL INSTALLED COSTS

The total installed cost (TIC) of individual equipment item functions has been modulated to include current delivered equipment costs to the Los Angeles area plus all associated materials and labor costs for the installation and functional operation of that piece (or pieces) of equipment. Paragraph 9.0 presents design criteria affecting TIC estimates. Equipment vendor prices have been solicited and received. Major vapor collection and blanket gas distribution piping has been handled as "equipment". Associated equipment costs include erection of the equipment, all associated piping, electrical, instrumentation, structural, civil, painting, start-up, engineering pro-rates, construction indirects, spare parts, and expendable costs necessary to fulfill its operating function. Assessing these cost increments to each functional equipment item is intended to allow the resulting module to be extracted from or added to a system in a fairly realistic manner. Engineering pro-rates approximate 10% of most equipment modules and construction indirects about 8%.[11] Natural gas and nitrogen blanket-gas initial terminal filling costs have been included as a vapor control system TIC.

This study has not optimized alternative equipment details except in major respects. Judgements have been made in these respects based upon engineering and operating experience. The accuracy of TIC estimates is in the order of ± 20%. Total installed costs for ballast and barge emission controls (Case I) equals $1.17 for Facility No. 1 and $1.99 for Facility No. 2 per B/CD throughput. Total installed costs for marine vessel plus shore-side tankage vapor control systems equal from $1.21 to $28.51 per B/CD throughput for Facility No. 1, and from $2.77 to $34.00 for Facility No. 2. (Cases II and VIIA). Cost intensities rise approximately 20-fold from Case I to Case VII.

6.3 DIRECT OPERATING COSTS

Functional equipment items have also been assessed with operating and maintenance labor factors, maintenance material, utility rates and other expendable costs. These operating costs have been reduced by load factors that have been developed from the transfer schedules described in section 4.0.

Utility rates have been selected from high and low cost areas for gas and electric power to industrial users on the East, Gulf and West Coast regions of the country: [12]

	high set (New Jersey)	low set (Texas)
$/KWH*	.050	.029
$/MMBTU/HR	3.225	1.275

*These are incremental power costs which include both demand and usage rates for major industries. Costs have arbitrarily been escalated 10% from the Federal Power Commission's last publication of "Typical Electrical Bills" dated January 1, 1976.

Operating and maintenance labor has been considered as costing $25,000/ manyear, including normal benefits and payroll burdens. Terminal facility staffs have been increased where believed necessary due to vapor control system complexities. Alternatively, fractional operating and maintenance labor and material costs have been assigned to equipment modules comprising each vapor control system.

6.4 UNCONTROLLED EMISSIONS

Base case emissions have been calculated for uncontrolled marine operations and for shore terminals with external floating roofs. Marine operations expel the bulk of all terminal emissions by ballasting to 20% of the cargo capacities in unsegregated compartments while at berth. Ballasting rates will usually start by opening a sea water valve to fill the compartment until the water level in the compartment approaches the ship's water line. Ballasting water rate diminishes at this time and if more water is desired in the compartment, ballast pumps are operated.[13] An overall average ballast rate of 50,000 BPH has been assumed for the 125M DWT tankers, while 20,000 BPH has been assumed for the 35M DWT tankers. An emission factor of 0.6 lbs. of hydrocarbon per 1000 gal. ballast water has been used for crude oil tankers and 0.8 lbs. of hydrocarbon per 1000 gal. for gasoline tankers. Ballast water has not been used with barging operations, but gasoline loading into dedicated barges in Facility No. 2 has been given an emission factor of 4.0 lbs. of hydrocarbon per 1000 gal. loaded.[1]

Base case external floating-roof tankage emissions have been calculated from the AP-42 standing loss formula:

$$L_s = 0.00921M\left[\frac{P}{14.7-P}\right]^{0.7} D\sqrt{150}\, V_w^{0.7}K_tK_sK_pK_c, \text{ in lbs/day}$$

For several years it has been apparent that the method of calculating hydrocarbon losses from floating roof tanks, as presented in API 2517 and adopted in AP-42, grossly overstates the losses to be expected from well-designed and well-maintained floating roof tanks. In 1975 it was postulated[14] that the major losses were wind-induced and that a secondary seal of some sort could eliminate this effect. In 1976 experiments by CB&I[2] supported this hypothesis and suggested that losses much lower than those calculated by the API 2517 method would be more appropriate. WOGA independently found at this time that emissions determined from this formula were overstated by some 40 to 60%, according to small scale tests on single seals.[15] Since then a variety of multiple seals have been prepared and some installed. These designs range from relatively simple close fitting wiper blades designed to eliminate wind effects (and hence, the bulk of the losses) up to full double seal designs that increase the effective sealing surface as well.

The API has initiated a project to update its technical bulletins on methods of estimating HC losses from external and internal floating roof tanks, scheduled for completion in early 1979. A similar project is planned for fixed-roof tanks.

This report is being prepared before a consensus has been reached, therefore, regarding the proper emissions factor to be used for new floating tanks equipped with an advanced sealing system. Accordingly, it is necessary to fall back upon API 2517 as a base case, recognizing that the cost effectiveness of various control alternatives will be less when this consensus has been reached. Standing losses are shown below with a 0.1 seal factor to illustrate the overall terminal effect of having double seals with that degree of sealing integrity. Other variables in the above formula are quantified below for both terminal facilities:

	Facility No. 1	Facility No. 2
M (vapor mol. wt.)	crude = 52	crude = 52 gasoline = 70
P (true vapor pressure)	crude = 4.6 psia	crude = 4.6 psia gasoline 6.8 psia
D (tank diameter)	340 feet	262 feet
V (wind velocity)	6 mph	6 mph
K_t (tank type)	0.045	0.045
K_p (paint factor)	0.9	0.9
K_c (commodity factor)	0.84	0.84 crude 1.0 gasoline
Number of tanks	24 crude oil	6 crude oil 2 gasoline

Normal standing losses have also been calculated for slops tanks and an API separator skim oil tank in each facility. Ballast water and oily sewer water separator losses have been estimated, as well as fugitive terminal emissions and transient (maintenance) emissions. Fugitive emission factors for these terminals have been modified from oil refinery emission factors in AP-42 by reason of the basis of refinery throughputs versus terminal throughputs, and of the difference in the items of equipment and their operating conditions in refineries and terminals. Fugitive emissions have been thereby reduced 57% both for the base case conditions and for secondary emission calculations.

Stack emissions from oil tankers and tug boat traffic within 5 miles of each terminal have been calculated from a scenario of their operations.

Large tankers and sea-going tugs for Facility No. 1 burn No. 6 fuel oil, while smaller tankers and harbor tugs at Facility No. 2 use only diesel oil.

Resulting uncontrolled base case pollutants have been calculated in short tons/year as:

	H-C		NO_x	SO_x	CO	Part.
Facility No. 1	$K_s = 1.0$	$K_s = 0.1$ *				
Normal						
Marine	2182	2182				
Tankage	659	66				
Fugitive	14	14				
Transient (No. 6 F.O)	35	35	148	111	40	11
Total	2890	2297	148	111	40	11
Facility No. 2						
Normal						
Marine	2295	2295				
Tankage	231	23				
Fugitive	8	8				
Transient (Diesel Oil)	44	44	280	20	136	0
Total	2578	2371	280	20	136	0

* ideal double seal operation.

6.5 CONTROLLED AND SECONDARY EMISSIONS

Controlled emissions are those atmospheric emissions which occur after vapor recovery facilities are installed and in operation. They include "secondary emissions", which are those resulting directly from the vapor recovery equipment itself. Where incineration is used for converting hydrocarbons to CO_2 and H_2O, emission factors for combustion pollutants have been used from EPA AP-42, second edition, for industrial process boilers burning natural gas. These are considered normal emissions. Only hydrocarbon emissions, however, apply to the economic cost effectiveness concept. Fugitive and transient emissions other than hydrocarbons have not been quantified. Total normal, fugitive, and transient secondary hydrocarbon emissions are summarized below in short tons per year for each vapor control system:

SECONDARY HYDROCARBON EMISSIONS ST/Y

Case No.	Facility No. 1	Facility No. 2
I	263	98.6
IA	263	98.6
II	29.8	8.4
IIA	28.8	8.5
III	293.3	107.4
IIIA	291.1	106.7
IV	295.9	112.0
IVA	291.5	108.0
V	31.0	9.3
VA	30.5	8.8
VI	274.7	102.7
VIA	272.5	101.2
VII	11.1	3.3
VIIA	11.1	3.3

Nitrogen and flue gas blankets (Cases VI and VII) emit only saturation quantities of hydrocarbon at most. Quantification of non-photochemically reactive hydrocarbons is not within the scope of this work effort, but a major portion of the secondary emissions from totally closed vapor control systems with natural gas blankets (cases IV and V) would be methane. Only pilot gas emissions have been assigned to emergency flares. Refrigeration compressor seal factors have been modified from refinery compressor seal factors in AP-42 by quantifying the difference in the average number of seals and temperatures involved. Fugitive terminal emission factor adjustments to oil refinery capacity factors have utilized "controlled" evaporative source emission factors from EPA-475/3-76-039, August 1976, "Revision of Evaporative Hydrocarbon Emission Factors", Attachment C.

TABLE 1 FACILITY No 1

CASE	DESCRIPTION	ALT.	TIC	ACC	HDOC	LDOC	R	U	C	HCE	LCE	X
		UNITS	$ M	$M/YR	$M/YR.	$M/YR	$ M/YR	S.T./YR	ST/YR.	$/ST.	$/ST.	SEE SECT. 5.0
BASE	EXTERNAL F.R. TANKS ONLY		0	0	0	0		0	0	0	0	
I	SAME AS BASE CASE EXCEPT REFRIGERATE MARINE EMISSIONS	I	2630	451	245	190	210	2890	1387	323	287	↔
		IA	6355	1090	123	68	238		1158	563	531	↔
II	INCINERATE MARINE EMISSIONS. BLANKET TANK W/NAT. GAS. FLARE EXCESS BLANKET GAS.	II	2720	466	3480	1520	-7796		77.8	4180	3480	↑
		IIA	11,290	1936	4380	1790	28		76.8	2240	1320	↑
III	SAME AS II EXCEPT REFRIG. MARINE EMISSIONS AND EXCESS BLANKET BEFORE FLARING (III ONLY, IIIA SAME AS IIA)	III	15,950	2735	5170	2740	329		341.3	2980	2010	↑
		IIIA	13,220	2267	3800	1550	238		339.1	2280	1400	↑
IV	SAME AS III EXCEPT RETURN EXCESS BLANKET TO SALES & RECYCLE NAT. GAS FROM HOLDERS	IV	34,300	5882	1070	760	336		343.9	2600	2470	↔
		IVA	50,340	8633	760	640	336		339.5	3550	3550	↔
V	SAME AS IV EXCEPT BALANCE SHIP & BARGE VAPORS WITH TANKAGE	V	40,160	6887	730	630	366		79.0	2580	2550	↔
		VA	56,140	9628	730	630	366		78.5	3560	3520	↔
VI	REFRIGERATE MARINE EMISSIONS. BLANKATE TANKS WITH N_2. RECYCLE N_2 FROM GAS HOLDERS.	VI	42,190	7236	2540	1700	336		322.7	3680	3360	↔
		VIA	50,090	8590	520	450	336		320.5	3410	3390	↔
VII	SAME AS V EXCEPT BALANCE SHIP AND BARGE VAPORS WITH TANGAGE USING FLUE GAS BLANKET.	VII	47,130	8083	700	580	366		59.1	2970	2930	↑
		VIIA	64,140	11,000	730	620	366		59.1	4010	3980	↑

TIC - TOTAL INSTALLED COST
ACC - ANNUALIZIED CAPITAL COST
HDOC - HIGH DIRECT OPERATING COST
LDOC - LOW DIRECT OPERATING COST
U - UNCONTROLLED H·C EMISSIONS
C - CONTROLLED H·C EMISSIONS
R - CREDIT FOR RETURNED H·C
HCE - HIGH COST EFFECTIVENESS
LCE - LOW COST EFFECTIVENESS
X - DIRECTIONAL NO_x, SO_x, CO & PART.

ISSUE	NO	DATE	REVISION	BY	CK	APPVD

ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	CUSTOMER	Environmental Protection Agency	DRAWING NUMBER	REV.
	PLANT	Contract #68-02-2838	153-1-22A	1
	LOCATION	Economic Summary, Facility No. 1		

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TABLE 2 FACILITY № 2

CASE	DESCRIPTION	ALT.	TIC	ACC	HDOC	LDOC	R	U	C	HCE	LCE	X
		UNITS	$M	$M/YR	$M/YR.	$M/YR	$M/YR	S.T./YR	S.T./YR	$/S.T.	$/S.T.	SEE SECT 5.0
BASE	EXTERNAL F.R. TANKS ONLY		0	0	0	0		0	0	0	0	
I	SAME AS BASE CASE EXCEPT REFRIGERATE MARINE EMISSIONS	I	1390	238	137	123	309.5	2578	514.6	31.6	25.0	↔
		IA	2260	388	108	94	321.1		440.5	81.9	75.3	↔
II	INCINERATE MARINE EMISSIONS. BLANKET TANK W/NAT. GAS. FLARE EXCESS BLANKET GAS.	II	1940	333	1765	801	-3373		60.4	2180	1780	↑
		IIA	3680	631	3165	1330	11.6		60.5	1500	775	↑
III	SAME AS II EXCEPT REFRIG. MARINE EMISSIONS AND EXCESS BLANKET BEFORE FLARING (III ONLY IIIA SAME AS IIA)	III	7510	1288	2310	1210	357		159.4	1340	886	↑
		IIIA	4510	773	2950	1240	321.1		158.7	1410	699	↑
IV	SAME AS III EXCEPT RETURN EXCESS BLANKET TO SALES & RECYCLE NAT. GAS FROM HOLDERS	IV	13,350	2290	535	470	359.1		164.0	1020	995	↔
		IVA	18,530	3178	470	420	359.1		160.0	1360	1340	↔
V	SAME AS IV EXCEPT BALANCE SHIP & BARGE VAPORS WITH TANKAGE	V	14,750	2530	520	490	373.1		61.3	1070	1050	↔
		VA	19,960	3423	510	480	373.1		60.8	1420	1400	↔
VI	REFRIGERATE MARINE EMISSIONS. BLANKATE TANKS WITH N_2. RECYCLE N_2 FROM GAS HOLDERS	VI	14,200	2435	1010	720	359.1		154.7	1280	1150	↔
		VIA	18,390	3154	250	230	359.1		153.2	1250	1250	↔
VII	SAME AS V EXCEPT BALANCE SHIP AND BARGE VAPORS WITH TANGAGE USING FLUE GAS BLANKET.	VII	18,100	3104	510	470	373.1		55.3	1280	1270	↑
		VIIA	23,800	4082	505	470	373.1		55.3	1670	1650	↑

TIC - TOTAL INSTALLED COST
ACC - ANNUALIZIED CAPITAL COST
HDOC - HIGH DIRECT OPERATING COST
LDOC - LOW DIRECT OPERATING COST
U - UNCONTROLLED H-C EMISSIONS
C - CONTROLLED H-C EMISSIONS
R - CREDIT FOR RETURNED H-C
HCE - HIGH COST EFFECTIVENESS
LCE - LOW COST EFFECTIVENESS
X - DIRECTIONAL NO_x, SO_x, CO & PART.

ISSUE	NO	DATE	REVISION	BY	CK	APPVD

ROBERT BROWN ASSOCIATES
CARSON, CALIFORNIA

CUSTOMER Environmental Protection Agency
PLANT Contract #68-02-2838
LOCATION Economic Summary, Facility No. 2

DRAWING NUMBER 153-1-22B
REV. 1

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6.6 MARINE RETROFITTING COSTS

Retrofitting costs have been estimated for typical barges and U. S. Registered tankers with manifolded venting systems and stack risers. Two hose connections are added to compartment vent manifolds so that either the port or starboard side of the vessel can be connected to dock hoses. A gate valve and flame arrestor is provided at each hose connection, and a gate valve is provided at each stack riser so that normal compartment venting can be restored at any time. Refer to drawings 153-1-13 and 15. Tanker hose connections are 18" and 12" at Facilities No. 1 and No. 2, respectively, and barge connections are 8" at Facility No. 2.

Retrofitting labor and material costs have been estimated per vessel as follows:

	Facility No. 1	Facility No. 2	
	120M DWT Tanker	35M DWT Tanker	Barge
Cases I, II, III, IV, VI	\$58M	\$23M	\$4M
Cases V and VII	\$74M	\$32M	\$4M

for tankers and barges which already have single vapor collection headers and stacks, as illustrated on the referenced drawings.

Retrofitting costs have not been included in cost effectiveness calculations because the number of various tanker and barge configurations that would service these hypothetical terminals have not been defined.

7.0 ENERGY RESOURCE CONSIDERATIONS

In the cost-effectiveness evaluation, cognizance has been taken of the value of hydrocarbon vapors collected and recovered with the monetary costs incurred. It is to be noted, however, that in the final analysis, the total net loss or gain of energy may transcend cost effectiveness. To this extent, consideration should be given to the fact that passive vapor control systems offer better thermal effectiveness than those which consume energy.

Cases VA and V offer the best thermal efficiencies in this study, considering equivalent utility heat values and Cases II and IIA offer the worst thermal efficiencies. The cost effectiveness of Case IIA, however, is better than Case V. In general, the more capital intensive vapor control systems evaluated are relatively more thermally efficient. Such considerations give reason to weigh energy resource along with monetary effectiveness.

8.0 SAFETY AND RELIABILITY CONSIDERATIONS

The costs of providing best available technology for public, personal, and property safety have been estimated, but while it is possible to quantify thermal and cost effectiveness, a comparative evaluation of total terminal facility safety can hardly be quantified, or even ranked. Historically, designers and operators in the petroleum industry have made efforts to eliminate "naked oil", and avoid explosive or potentially explosive vapor spaces. The blanketing of vapor spaces in tanks or vessel compartments, and the elimination of vapor spaces altogether by the use of floating roof tanks, are such examples. Designs have avoided the need to depend upon seals, purges, or flame arresting devices to prevent the ignition of large volumes of gas. The intrinsic nature of vapor recovery and/or vapor incineration systems, however, intimately involves these concerns. It must be recognized that these systems necessarily represent an inescapable compromise with safety in the interest of vapor recovery.

The distinction between potential emissions and controlled emissions has been of increasing environmental concern. It is sometimes necessary to evaluate a facility in terms of what would happen upon failure of the emission control provisions. In such instances, external floating roof tankage with small vapor volumes, and segregated ballast offer clear safety and reliability advantages. These advantages are either contrary to or not discernible in cost or thermal effective analysis.

In addition to the concerns with controlling large low pressure gas volumes are those relating to fires in large cone roofed crude oil tanks, as described in paragraph 9.1.4 Fire Protection. In view of these concerns, special design considerations and sizeable investments must be provided to vapor control systems to enhance safety and reliability:

- Operating pressures well below relief valve settings,
- Oxygen analyzes monitoring below each tank vacuum relief valve, at marine vessel vapor collection headers, and at blanket gas storages.
- Automatic gas purges to reduce unacceptable oxygen concentration levels,
- Flame arrestors at major equipment,
- Remote manually controlled block valves on major vapor collection branches,
- Circulating butane through marine vessel vapor collection systems,
- Water seals before incinerators and refrigerators,
- Automatic flare and blower shut down at loss of forward gas-flow to flares,
- Alarms to acknowledge automatic corrective actions taken for high oxygen levels, no gas-flow to flares, etc.,
- Enclosed drains to covered API separators,
- Additional fire water capability for cone roof tankage,
- Detonation barriers,
- Strategic equipment and piping layouts.

Costs for the above provisions have been included in each alternative vapor control case evaluated.

9.0 VAPOR CONTROL DESIGN CRITERIA

Although basic design criteria is not expected to affect cost effectiveness significantly, design concepts have assumed 3,000 psf soil loadings (other than that for tankage), negligable frost lines, no snow loads, ambient weather above freezing, 100 mph winds, 70°F sea water temperatures, and essentially level terrain. Vapor temperatures in marine vessel and shore tankage storages averages 75°F annually and wind velocity averages 6 mph. Siesmic loads have not been calculated.

Some refrigeration power loads are high. Transformer capacity from feeder voltage to 4160V has been assumed to be either available or supplied by the power company and reflected in the power billings. All power lines having 110V or less are run overhead, while the rest are run below grade. NEMA Class I Group D Division 2 electric area classification has been assumed throughout.

Pipe supports at grade are assumed to have adequate space available for vapor control system piping. All large vapor collection and distribution piping is elevated on shore, while that on piers has been estimated with having special support brackets.

Land value has not been assessed to design arrangements, but all vapor control system equipment has been layed out on terminal plot plans for estimating pipe lines and electrical runs. Ample room is available, including ground flares using 250' x 500' areas because of low feed gas pressures. Refer to drawings 153-1-1 and -3, p. 21 and 26, for general plot plan arrangements.

9.1 SYSTEM SAFETY FEATURES

Any vapor control system in a terminal must be as automatic as reliability and the best technology will allow, because the primary function and operating objective is to transfer bulk petroleum quantities. Operating attention must be alerted, however, whenever a potentially dangerous condition develops in the control system, and an automatic sequence of operations should be actuated, wherever feasible, to mitigate the dangers. This means a shut down of the vapor control system as a last resort. At this time, fixed roof tanks breathe through their PSVS (conservation vent valves), which is when oxygen analyzing controllers play an important part in preventing explosive gas mixtures.

Instrumentation has been estimated to accommodate the above philosophy in each vapor control case. Alarms have been estimated both locally and in a centralized terminal control room, and gas purges are automatically actuated in all cases, for excessive oxygen levels, in both terminal facilities at the following locations:

1. Each fixed roof storage tank, including slops and skim oil tanks
2. Each flexible diaphram gas holder
3. Each floating roof gas holder
4. Covered API separator
5. Marine vessel vapor collection headers, including Case VII. Totally enclosed Cases V and VII have automatic emergency bleeds to atmosphere at very high oxygen levels.

Case VII does not have a reliable automatic source of purge gas, except in item 5 above where a slave butane circulating system is available from the marine emission refrigerator. When a high oxygen alarm sounds for any item 1 through 4 above in Case VII, flue gas from ships' stacks or from inert gas generators are manually attended. Liquid nitrogen in pressure storage is available for reasonable emergency purges in Case VI. When oxygen levels have been restored by these gas purges, oxygen analyzing controllers automatically stop the alarms and purges. Local overrides are provided in each case. Similar automatic oxygen alarm and purge systems have been successfully operating in natural gas blanketed oil refinery tank farms in recent years[16] .

9.1.1 Control Instrumentation

Refrigerator units and blowers are activated by a flow switch in collection headers for marine vessel emissions, and by a disc level switch in flexible diaphram holders for tankage emissions. Blowers of refrigeration vapor effluents are activated with the refrigerator unit and blowers of flue gas from ships' inerting systems are manually activated. Treating units are manually set to operate at a selected flow rate, as are inert gas generators for Case VII. These operations are relatively complex and need to be lined out during start up for fairly constant production rates. Nitrogen flow for Case VI is activated from liquid nitrogen supplies automatically for oxygen control, as mentioned above, and manually for gas holder inventories. Conventional switch gear technology for NEC Class I Group D Division 2 areas is applicable throughout.

Best available technology for oxygen analyzer-controllers is with the use of sensor cells that produce a linear millivolt output potential with concentrations of oxygen only. These controllers have been developed to continuously monitor and record oxygen concentrations, except during scheduled three-minute cycles once every hour while they automatically calibrate their output with ambient air. Cell life lasts at least 9 months with that amount of oxygen exposure and these small cells are very easy and inexpensive to replace. When output voltage drifts away from that representing 20.9 vol. % during calibration cycles, either an alarm can call an operater's attention to the need to manually recalibrate the instrument, or recalibration can be automatic until such time that the extent of deviation calls for cell replacements. In view of the quantity of these controllers proposed for the two terminal facilities, and to minimize maintenance staffing, automatic self-calibrating instruments have been estimated in this study.

Tankage blanket gas control valves are self-contained pressure regulators that are sensitively counter-weighted against atmospheric pressures. Table 3 illustrates their settings for each vapor control case, as shown on flow drawings 153-1-7 through 153-12A. Atmospheric vacuum relief valves settings equate to a 25 psf vacuum on the basis that fixed tank roof live loads are designed to support 50 psf, 25 of which is for vacuum. Snow loads would add to this 50 psf live load. Pressure relief valve settings in Table 3 show pressure ranges within which pressure regulators operate.

TABLE 3

BLANKET GAS PRESSURE CONTROL VALVE SETTINGS IN OSIG.

(Ounces Per Square Inch Guage)

Case	Atmospheric Pressure Relief Setting	BLANKET GAS SOURCE: Floating Roof Holder, start to open	Floating Roof Holder, full open	Purchased Gas, start to open	Purchased Gas, full open	Atmospheric Vacuum Relief Setting
II	+ 0.85			- 0.5	- 1.3	- 2.78
III	+ 0.85			- 0.5	- 1.3	- 2.78
IV	+ 0.85	- 0.1	- 0.5	- 0.9	- 1.3	- 2.78
V	+ 2.27	- 0.1	- 0.5	- 0.9	- 1.3	- 2.78
VI	+ 0.85	- 0.5	- 1.3			- 2.78
VII	+ 2.27	- 0.5	- 1.3			- 2.78

Flares and incinerators, both being multi-burner ground flares, are protected from flash-backs by:

1. Enrichening lean or explosive gas mixtures with hydrocarbon concentrations slightly too rich to burn.
2. Providing an enclosed 3" water seal, continuously maintained automatically with conventional instrumentation.
3. Providing a continuous fuel gas bleed down stream of the water seal and a flow switch so that if a positive gas flow towards the burners is not detected, pilot gas is shut off, feed blowers are deenergized, feed blower discharge valve is closed, local alarms are sounded, and an alarm in the centralized control is sounded.

Pilot flame detectors are also provided that activate the events listed in Item 3 above if pilot burners are extinguished. A remote control panel provides a means of manually igniting pilots.

9.1.2 Operating Features

With daily functional operations of each vapor control system being substantially automatic, manual operating burdens imposed upon either terminal facility by vapor control systems is limited to handling marine-to-dock hose connections, rectifying emergency upsets, and managing blanket gas inventories.

Emergency upsets are manifested by the alarms mentioned above, namely from oxygen analyzers or flaring operations. Excess oxygen conditions are rectified by natural gas, nitrogen, or flue gas purges, consistent with safe blanket gas inventories. If such purges deplete those inventories, then a shut-down decision needs to be made. The major variables involved in this decision involve:

1) Scheduled tanker receipts and alternatives
2) Scheduled pipeline deliveries and alternatives
3) Availability of blanket gas from outside sources
4) Length of time required for maintenance to repair the situation causing the high oxygen levels
5) Shutdown and startup time and manpower availability.

Storage tanks can be removed from service without interrupting operations of the other tanks. In view of the large ducts and very low pressure blanket gas conditions involved, aluminum slip blinds can be used between flanges having jack screws, instead of investing in many large valves which are rarely used. Valves must be used, of course, wherever a line could reasonably need to be blocked out fast for safety reasons. Valves have been estimated in vapor headers between groups of tanks, for instance, as a fire safety precaution.

Redundancy of equipment for operating flexibility is limited to blowers and small refrigeration condensate pumps. Other items of equipment are too costly and massive for duplication in such an ancilliary function as vapor control. Certain safety instrumentation is redundant.

Shutdown and start-up procedures must avoid large volumes of gas passing through the explosive range, and the dryness of possible pyrophoric iron sulfide surfaces of equipment which will be exposed to air. Storage tanks to be taken out of service from a gas blanketed system should be first filled with sea water (using the fire water pump) and then blinded from other tankage. The small ullage remaining above the water should then be swept gas free by purging with nitrogen from one side of the roof to the other. Atmospheric emissions therefrom are transient. With air vents open on the tank roof, sea water should drain from the tank through the API separator until no visible oil appears, after which it could run directly to sea until the tank is almost empty. Last portions should go through the separator again. Tank shell manholes are now ready to open. Interior surfaces are wet and iron sulfide has little, if any, fuel to ignite. Limited preventative maintenance may even be justified for checking fixed roof tank relief valves and cleaning flame arrestors.

Appropriate operating labor has been added to the equipment modules that comprise each vapor control system.

9.1.3 Maintenance Features

Maintenance burdens imposed by vapor control systems are more extensive than operating burdens because of the need to maintain reliability without redundancy in highly automated complexes. The handling of sour crudes greatly magnifies this difference, although operating problems also are increased. A primary feature complicating maintenance problems in vapor control systems handling sour crude vapors is the potential danger of H_2S to personnel, and of fires from pyrophoric iron sulfide. Although the terminal models in this study does not define the crude sulfur content, it is assumed in this section that some H_2S prevails. Maintenance problems with H_2S are most imminent when installing slip blinds in large vent lines to isolate storage tanks. Here mobile cranes are needed to handle large aluminum blinds and impact wrenches. Scaffolding may be needed. In any event, safety-tested gas masks must be worn during the opening, spreading, blind-inserting, and flange-tightening operations. Similar precautions and equipment is needed for removing the blind. Other maintenance activities regarding vapor control include that for:

- Inspecting and maintaining external floating roof seals
- Rotating equipment
  - Blower packing glands and bearings
  - Cold refrigeration pumps
- Flexible diaphram inspections and replacements
- Floating roof gas holder fabric (dry seals)
- Fixed roof relief valve checks
- Electronic control panels and switch gear
- Refrigerator compressors (reciprocating)
- Gas treating units
  - Compressor maintenance

Sponge iron replacements*

Sea water shell and tube exchanger cleaning

- Flame arrestors
- Oxygen analyzer cells
- General instrumentation

* Sponge iron replacements vary in frequency with H_2S concentrations and the rate of natural gas circulations.

Maintenance labor and material costs have been added to the equipment modules that comprise each vapor control system. Negative values have been assessed to fixed roof tankage for the savings in not continuously inspecting and repairing external floating roof seals.

9.1.4 Fire Protection

It should be recognized here that above ground fixed roof tankage of the sizes in Facilities No. 1 and No. 2 is not normally used in the petroleum industry for crude oil because of the potential hazards caused by fires. Crude oil tankage usually contains a bottom layer of water. Heat is eventually convected to this layer from surface fires, resulting in boil-overs that can literally spill all of the burning crude oil from the tank onto surrounding areas. Resulting flame impingements, especially down wind, and radiation, can overheat adjacent cone roof tankage. Atmospheric pressure reliefs will ignite. If overpressures and/or heat destroys adjacent cone roofs and their crude oil contents are ignited, a holocaust can result. Gas-blanketing fixed roof tanks greatly reduces the possibility of ignition, but it does not eliminate it because of human errors, particularly by overfilling, or not following established procedures while taking tanks in and out of service.

National Fire Protection Assoc. requires 9080 GPM and 5390 GPM of fire water for cooling cone roof tank surfaces in Facilities No. 1 and No. 2 respectively, compared to only 150 GPM and 112 GPM for either external or internal floating roof tanks, because of the relatively minor coverage between floating roof seals (or foam dams) and tank shells[17]. The difference in cost for additional coverage has been charged to all cases (not alternative cases) except Case I, including additional form concentrate inventories. Foam chambers, or subsurface foam inlets, and fire water monitors, are considered to be consistant in all cases with that in the Base Case for both terminal facilities.

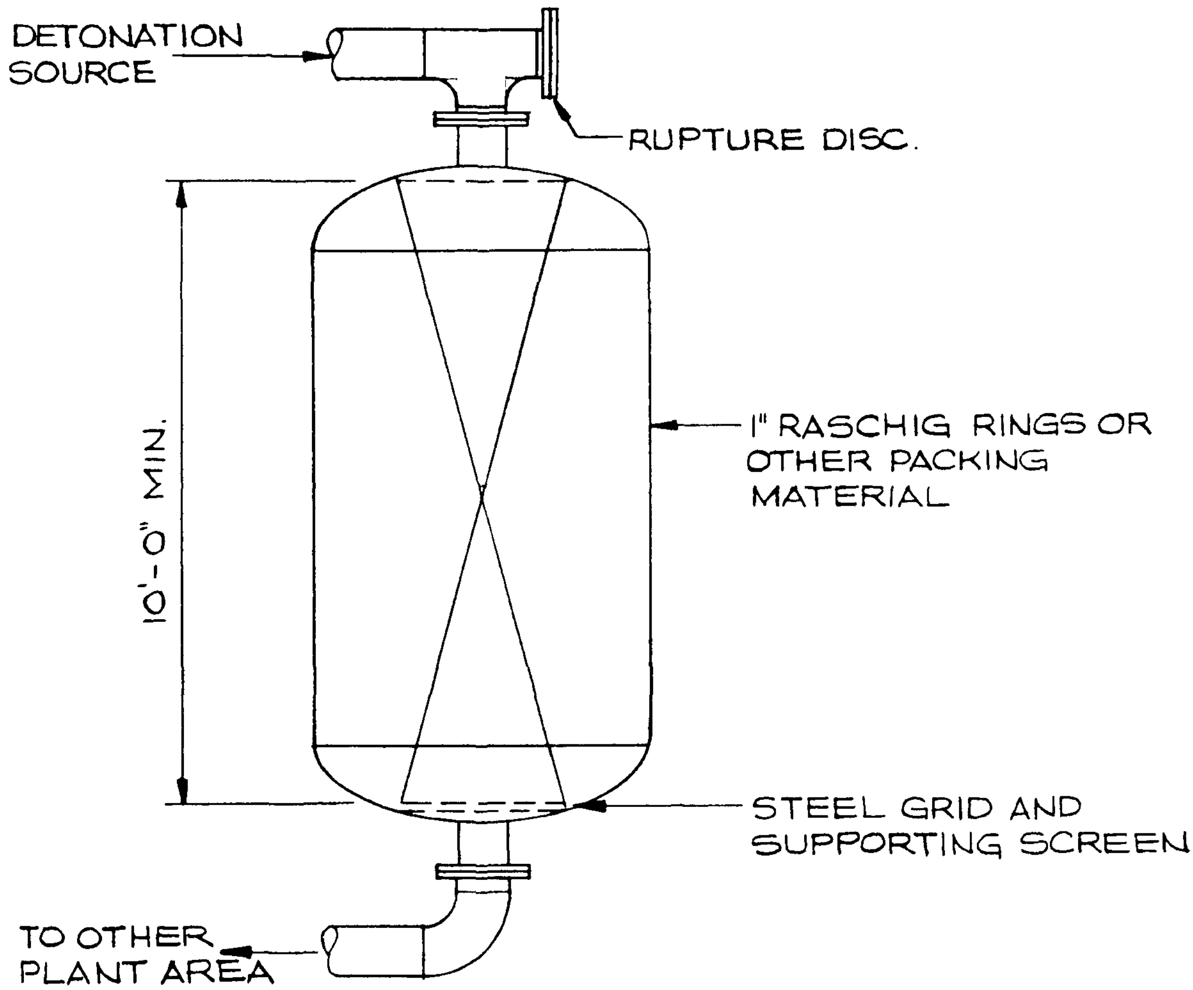
9.1.4.1 Flame Arresting - Cost estimates have included circular crimped ribbon type flame arrestors[17,19] located on dockside piping at each ship hose connection, at the inlet to each refrigerator and incinerator (flare), at the inlet header from tankage to flexible diaphram receivers, and at the inlet header to floating roof gas holders, even with non-combustible blanket gases. UL approved flame arrestors are available in smaller sizes (i.e.: 10"-12") and can be alternatively used in a battery of parallel units between two headers. Flame arrestors are not located on storage tank vents, in keeping with the API Committee on Safety and Fire Protection[20]. Water manometer taps should be provided to periodically test the pressure drop across each flame arrestor, and maintenance should schedule fast clean-out procedures with minimum shutdown time and expense for each arrestor. Sour crudes will increase the rate of arrestor plugging.

Bursting discs are located at the extremities of vapor collection headers in a manner such that pressures resulting from normal burning of combustible gas mixtures in the headers can be relieved without serious equipment damage. Normal burning is meant to be that when the gaseous products of combustion flow away from the flame front and have a density and pressure less than that of the unburned gases. Detonation occurs when the inertia of the products of combustion cause substantially higher pressures than the fresh unburned gas before the flame front. Here bursting discs and flame arrestors have little, if any, value unless they are arranged as detonation barriers.

9.1.4.2 Detonation Barriers - The range of gas concentrations in volume percent with air that can result in detonations are[18]:

	Flammability Limits		Detonation Limits	
	lean	rich	lean	rich
Methane	5.3	13.9	8.5	11.0
Gasoline	1.3	7.3	2	

The radial pressure exerted by detonation against the sides of a collection header is directly related to the initial pressure of the gases. At these low vapor control pressures, detonation pressure of a methane-air mixture may only be from 500 to a peak of 1500 psia radially, while axial pressures would be 1 1/2 to 3 times higher[21]. Detonation wave velocity is relatively low also because of the low initial pressure, perhaps about 1000 feet per second. Some detonation velocities reach 6000 FPS[18]. Consequently, detonation barriers may not be out of the question for vapor control systems. One such arrangement is shown by drawing 153-1-24[21]. Time has not been available in this study, however, for locating and designing such barriers, but estimated contingencies have been provided for their application.



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	PLANT CONTRACT #68-02-2838	153-1-24	0
	LOCATION DETONATION BARRIER		

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9.2 EQUIPMENT RELIABILITY

As mentioned previously, the primary function of oil terminals is to transfer bulk petroleum liquids and not to operate vapor control systems. Equipment reliability is obviously important, not only because it is usually unattended, but also because large gas volumes can become potentially dangerous by the inclusion of oxygen. The magnitude of these equipment investments do not allow reliability in the form of redundancy in most instances. Consequently, the equipment used should be intrinsically high in quality and commercially proven in the application employed.

9.2.1 External Floating Roofs

Tankage having these roofs apply to the Base Case and Case I vapor control systems for both terminal facilities, including slops and skim oil tanks as well as main tankage. Tank seals have been priced for secondary seal arrangements, having a bottom mechanical shoe-type seal and a top fabric wiper seal. Helper springs on top seals are not considered consistant with tank seal factors (K_s) of 1.0. Since alternative vapor control systems compare only the difference in cost and emissions from the Base Case, other storage tank features, such as the tank shell and floor construction, foundations, and general appurtenance costs, cancel out. No covers are assumed on the API oily water separators for the Base Case and Case I facilities.

Tanks in Facility No. 1 are only 48 ft. high by 340 ft. in diameter, presumably to accomodate a 3000 psf soil loading. It should be noted that this height is not as economical in cost per unit capacity as is a $60^{\pm}$ foot high tank, especially with floating roofs. This feature has appreciably lessened the cost effectiveness of vapor control systems with internal floating roof tanks, in this study.

It is believed by RBA that if floating roofs were evaluated with special double seals, instead of single seals, seal factors of as low as 0.1 could be obtained.

9.2.2 Internal Floating Roofs

Tankage with these roofs apply to all alternative vapor control system cases. API separators in these cases are assumed to have conventional coverings, but slops and skim oil tanks in these alternative cases also have internal floating roofs.

Reliable designs for floating roofs in tanks 340 ft. or 262 ft. in diameter would be difficult. However, they have been priced for having single decks over a buoying means, and with a single fabric seal. Costs were not obtainable for a lever shoe-type seal and upper wiper seal, comparable in integrity to that of external floating roof seals, since these are not a currently conventional design for such tankage[22].

Fixed roofs have been priced for being 3/16" thick steel in all cases except VA and VIIA. In these cases tank vapors are in balance with those from ships at berth and 1/2" thick steel fixed roofs have been priced in order to provide more operating pressures available below tank relief valve settings. Case VIIA has an additional 1/8" corrosion allowance. All fixed roofs are designed for a 50 psf live loading, 25 of which is for vacuum. Snow loads would be added to the 50 psf live load. Pressure relief is set by the weight of the roof, or 0.85 osig for 3/16" thick roofs and 2.27 osig for 1/2" thick roofs. Vacuum relief is set at 25 psf, or 2.78 osig vacuum. Since natural gas, nitrogen, or flue gas blankets are employed in all alternative cases, except Case IA, only this latter case has internal floating roof tankage with air vents in the upper shell. Otherwise, blanket gas enters and leaves each tank through nozzles as near to the center of the cone roof as structural roof supports will allow and no vents, of course, exist. Refer to drawing 153-1-23 p.59.

Only the price difference between these fixed and floating roofs have been compared to the Base Case external floating roofs. The price of painting all interior ullage surfaces to prevent carbonic acid corrosion has not been added to the internal floating roof tankage costs for Case VIIA, which utilizes flue gas for blanketing, in view of the decisions made for Valdez. Here, where scrubbed flue gas is used as a blanketing media, it was concluded after some study that the cost of applying errosion resistant paint would be forestalled until such time that errosion probes indicated its necessity[10]. This approach has been applied to Case VII as well.

9.2.3 Cone Roofs

Tankage with these roofs apply to all cases except Case I, where external floating roof tanks remain as in the Base Case. All cone roofs, including API separator covers, are of 3/16" thick steel, except those in Cases V and VII where tankage vapors balance with those from tankers at berth. Cone tank roofs in these cases are 1/2" thick steel to provide for more operating pressures as mentioned above, and Case VII has an additional 1/8" corrosion allowance. Pressure relief settings are as described above. Blanket gas enters and leaves through nozzles as near to the center of the cone roof as structural roof supports will allow.

9.2.4 Flexible Diaphram Gas Holders

These gas holders are designed to collect net blanket gas expulsions from cone or internal floating roof tankage at storage tank ullage pressures of about 0.5 ounce per square inch (osi) for tanks with 3/16" thick fixed steel roofs (that relieve to atmosphere at 0.85 osi) or at storage tank ullage pressures of about 1.35 psi for tanks with 1/2" thick fixed steel roofs (that relieve to atmosphere at 2.27 osi). Thus, the flexible diaphram in these gas holders must be as light in weight as durability will allow. Diaphrams are contained in steel tanks with self-supported roofs, and are attached midway up the shell. Live roof loads of 25 psf have been cost estimated. Snow loads would require additional loading. Full bag volumes occupy to about 90% of the tank volume.

Vapor collection ducts have been sized and costs estimated for Buna-N diaphrams with nylon inserts that weigh 0.2 osi. This material has been used successfully in similar service at only 0.144 osi[23]. A spare blanket should be constantly in warehouse stock, however. A heavy 1/2" thick steel disc in the center of the diaphram keeps it from becoming askew in the tank as it rises and falls. A level switch outside of the enclosed steel tank housing the diaphram, operated by the level of the center disc, energizes tank effluent blowers or refrigeration units when the tank is about 90% full, and deenergizes them when the center disc reaches the bottom of the tank.

The size of most flexible diaphram tanks estimated for these models are believed to be about maximum for those in commercial use[23]. Larger gas volumes, even at the same low pressures, are stored in counter-weighted floating roof type gas holders, which are much more expensive per unit volume, as described below. Flexible diaphram tank groups have been sized to hold at least one hour of maximum storage tank vapor expulsions at both terminal facilities.

9.2.5 Floating Roof Gas Holders

These gas holders are designed to recycle blanket gas for terminal tankage in order to minimize the need for new gas supplies. Thus, an operating pressure of 12" water pressure (6.91 osi), which can be supplied by a blower, has been selected as a reservoir pressure.

Dry-seal type telescopic holders with tee fenders and flexible Buna-N vinyl seals have been cost estimated as being subcontracted for construction in place. Group capacities have been based upon supplying terminal throughput pump-out replacements for 1 1/2 days without a ship delivery. Total volumes amount to 12.5% and 17.7% for cone roof and internal floating roof tanks, respectively, at Facility No. 1. Those at Facility No. 2 collectively amount to 14.0% and 21.6% of the cone roof and internal floating roof tankage there. The sizes of these individual holders has been limited to large commercial applications, generally under 200 ft. in diameter and height. The cost of these holders is the major reason for the cost ineffectiveness of Cases IV, V, VI, and VII, and the reason for not providing 100% terminal storage volumes for blanket gas.

9.2.6 Blowers

Blowers are motor driven, aluminum, centrifugal type, industrial exhaust fans with axial blades. Seal leakage is restrained by graphite base packing seals with stuffing box and lantern rings. Blowers have been rated for a differential head of 20" water at actual inlet gas densities, except flue gas boosters at dockside and boosters to ground incinerators or flares. All are aluminum construction, graphite seals, and explosion proof motor drivers and have been selected for non-sparking features, in Class I Group D Division 2 electrical areas. Similar blowers have been used successfully in explosive gas mixtures in other industries[24].

Blower services have been spared mostly by having 3-50% units. In very small sizes they have been allowed a 100% spare. In tanker ballast and barge loading emissions services, one unit has been provided for each berthing location. Flue gas blowers that transfer stack gas to floating roof holders in Case VII and those supplying waste gas to flares and incinerators, are turbo-type, having a differential pressure of 1.5 psi.

9.2.7 Refrigerator Units

These have been priced as skid-mounted units with most of the operating equipment in a pressurized housing for NEC Class I group D Division 2 areas. Vapors are refrigerated and exhausted at atmospheric pressures and liquid water condensate is pumped to the API separator. Condensed hydrocarbons are pumped by the units to about 50 psig at the coldest temperatures reached by refrigeration. When essentially all hydrocarbons heavier than ethane are to be condensed, these temperatures are about $-170^{o}F$. Partial condensations, such as those required for removing only tankage vaporizations from a saturated blanket gas media, hydrocarbon liquids are pumped away at warmer temperatures, such as $-80^{o}F$ or so. The more hydrocarbons are condensed and removed, the less thermally efficient the unit becomes because these removals are not heat recoverable. Vapors leave the unit from 0^o to 40^oF, depending upon how much hydrocarbon is condensed.

Continuous operations are realized by alternating coil sections for refrigeration and defrosting. Liquid water is first removed at the hydrate point, about 35^oF. Additional water is removed as liquid by defrosting. Where flue gas is used in Case VII, and essentially all hydrocarbons are condensed, about two-thirds of the CO_2 precipitates at -152^oF at the partial pressures involved, and then sublimates upon defrosting. The remaining CO_2 stays in the vapor state. Installed horsepower has been estimated for start-up operations. Cost also include constant monitoring capability. Marine emission refrigerators in all cases require a slave n-C_4 circulating system to increase hydrocarbon concentrations in marine collection headers above explosive limits. Complete condensation and vaporization mechanisms for this compound in the proper quantities for all cases have been estimated.

Very little is known about hydrate formations at these low temperatures and atmospheric pressures, but it is not expected to be a major problem[5]. Hydrates are an accumulation of water molecules that capture a hydrocarbon molecule, and most frequently occur when high pressure, water saturated, gas is depressured. About 17 mols of water are needed for hydrating 1 mol of propane, and 7.9 to 8.5 mols are needed for 1 mol of ethane[5]. Hydrate formation would be collected in a solid state with ice, and that portion of the propane and lighter hydrocarbons that do form hydrates can be vaporized at defrosting temperatures. Even if vaporizations were collected and chilled again in the refrigeration (nondefrosting) coils, a build up of light ends may not liquify and consequently escape to atmosphere as vapor. However, neither the amount of water vapor available at these cold temperatures, nor the low operating pressures, are typical of the prerequisites for hydrate formation. Even though traces of H_2S may promote hydrations, and the propane constituent of crude vapors is significant, no evidence is known that precludes the ability of staged refrigeration to liquify propane and heavier hydrocarbons at -170^oF and 14.7 psia. It is known that gasoline vapors can be so condensed without hydrate problems[25].

Of more concern is the plugging up of refrigeration heat transfer surfaces with solid CO_2 in Case VII. None-the-less mechanical design is expected to be able to provide enough heat transfer to accomplish the required temperature levels.

9.2.8 Flares and Incinerators

Both incinerators and flares in this study are multi-tipped vertical burners at grade having pilots and flames which are generally concealed from ground-level views. Both are arrangements of vertical pilots and burners having below grade header manifolds and a remote ignition system. Adequate fuel gas is admitted into the upstream vapor lines of so-called "incinerators" so that the mixture can sustain combustion, i.e.: having at least 150 Btu/CF. Technically speaking, incinerators handling gases that are premixed for combustion become flares, flares being defined as that which burns gases that sustain their own combustion.

These banks of vertical burners require inlet waste gas pressures of 1.5 psig in order to burn crude vapors containing up to 15 vol. % propane smokelessly   Air fans, actuated by gas flow switches can provide supplemental primary air to assure smokeless burning at these low gas pressures if such is found to be necessary. An enclosed 3 inch water seal and flame arrestor prevent back-flashes. Consequently, flare areas and burner heads are large. Real estate requirements vary from 120 ft. by 100 ft. to 150 ft. by 400 ft. Banks of burners are charged with gas by stages. The number of pilot burners vary in number from four (4) to eight (8). Each pilot burns about 200 SCFH of natural gas continuously from a separate commercial natural gas source for safety reasons. Automatic ignition is accomplished from a local panel just outside the fenced-in burner areas. Flame failures automatically shut down feed sources to these flares or incinerators, and sound alarms accordingly.

9.2.9 Inert Gas Generators

Inert gas generators are used in standby service for Case VII only. These natural gas near-stoichiometric burners have been arbitrarily sized for reducing an empty storage tank from 21 vol. % to 4 vol. % oxygen within 48 hours while producing 1.0 vol. % oxygen. Scheduled tankage turnarounds would be by tank flooding procedures, however, as described under operating features, paragraph 9.1.2. Unit sizes produce 100,000 SCFH of a flue gas at about 10" H_2O with the following average compositions, after being lined out:

0.5 vol. % oxygen
91.2 vol. % nitrogen
7.5 vol. % carbon dioxide
0.83 vol. % water vapor
neg. carbon monoxide

Water removal is accomplished physically by heat exchange with sea-water cooling to a dew point of about 80°F. Carbon dioxide and/or further water removals are considered too expensive for this standby facility, especially since tanker stack flue gas, the primary source of this blanket gas, is not treated.

Inert gas generators are potentially dangerous in that more CO can easily be generated than is shown above in attempting to minimize oxygen. They are usually difficult to line out, and if their delicate flame is extinguished, the generator produces a very explosive mixture of gases into the blanketing system. For these reasons, Case VII preferentially obtains its flue gas from ships' stacks at berth, assuming that the ships' boilers operate at no more than 20% excess air at reduced boiler loads. Even so, this source is also ladened with CO, especially in Facility No. 2 where diesel driven tankers are serviced exclusively.

9.2.10 Treating Units

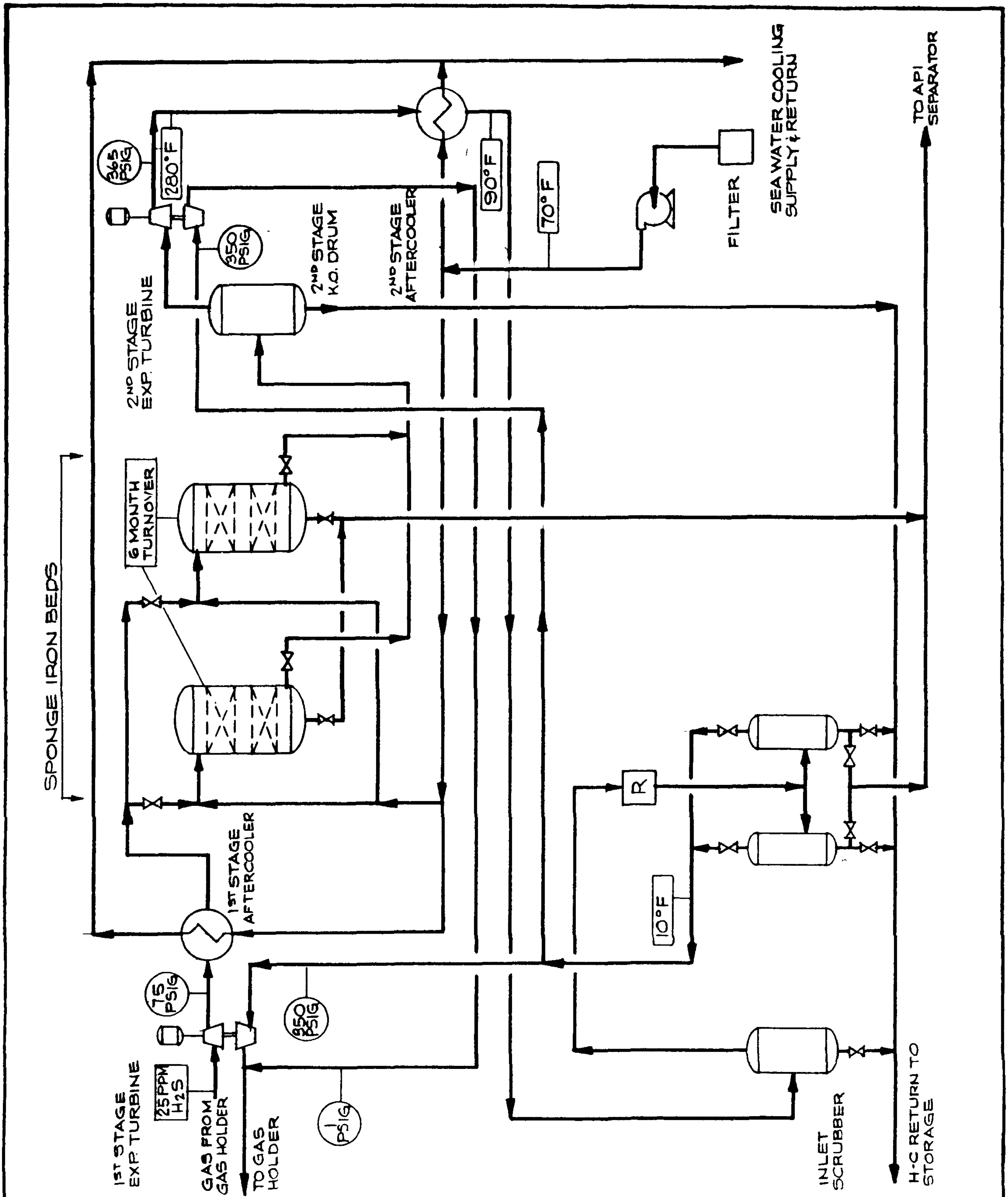
These units are needed to assure that excess blanket natural gas volumes meet pipeline quality requirements in Cases IV and V. They remove sulfur compounds, water, and vaporized hydrocarbons from blanket gas to be either recycled or returned to sales. Because of the investment costs for compressing large volumes of gas for sales at 350 psig, treating units have been reduced in design throughput by the difference in load factors between blanket gas demands and excesses, and recycled blanket gas is passed through power recovery turbines back to low pressure storages. Large feed gas holders allow these reduced treating unit rates to be fairly constant and continuous. A flare is available for unit interruptions or for disposals with filled blanket gas holders and no sales outlets.

Treating units consist first of a guard chamber of sponge iron to remove stray sulfur compounds at 25 psig and fairly ambient temperatures.

Any condensed hydrocarbons are also passed through the sponge bed for sulfur removal. Water removal is then accomplished at a pipeline header pressure of 350 psig. In cases having cone roof tankage, where significant amounts of hydrocarbons are present, $10^{o}F$ dew point temperature is reached by indirect refrigeration. Defrost cycles gravitate water with any hydrocarbons to a closed API separator in a closed drain system. In cases where 99% of the vaporizations from cone roof tankage is restrained by using internal floating roof tankage, water removal is obtained by glycol absorption. Refer to drawings 153-1-21A and 21B. Atmospheric emissions from the very small fired heater and regenerator vent are assessed to Case IVA and VA, where these units are used. Transient emissions also occur periodically from the opening of sponge iron chambers, the changing of their contents, and the cleaning of glycol filters. Refer to paragraph 5.6, pages 58 and 60, for further details.

In some locations it may be feasible to return sour gas to the gas utility for their processing, along with their other gas receipts. The cost to clean up this gas has been estimated for Cases IV and V because that cost would supposedly be reflected in the difference between sour gas delivered and sweet gas received in any case. Local negotiations could, perhaps, reduce the treating costs estimated.

A lead factor of 90% has been calculated for Case IV, but Case V theoretically has no load factor, since blanket gases leave the terminals in tankers. The same capital costs have been estimated for both cases, but a 10% load factor has been assigned to Case V treating units.



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ROBERT BROWN ASSOCIATES CARSON, CALIFORNIA	**CUSTOMER** ENVIRONMENTAL PROTECTION AGENCY **PLANT** CONTRACT #68-02-2838 **LOCATION** TREATER UNIT WITH CR TANKAGE	**DRAWING NUMBER** 153-1-21A	**REV.** 0

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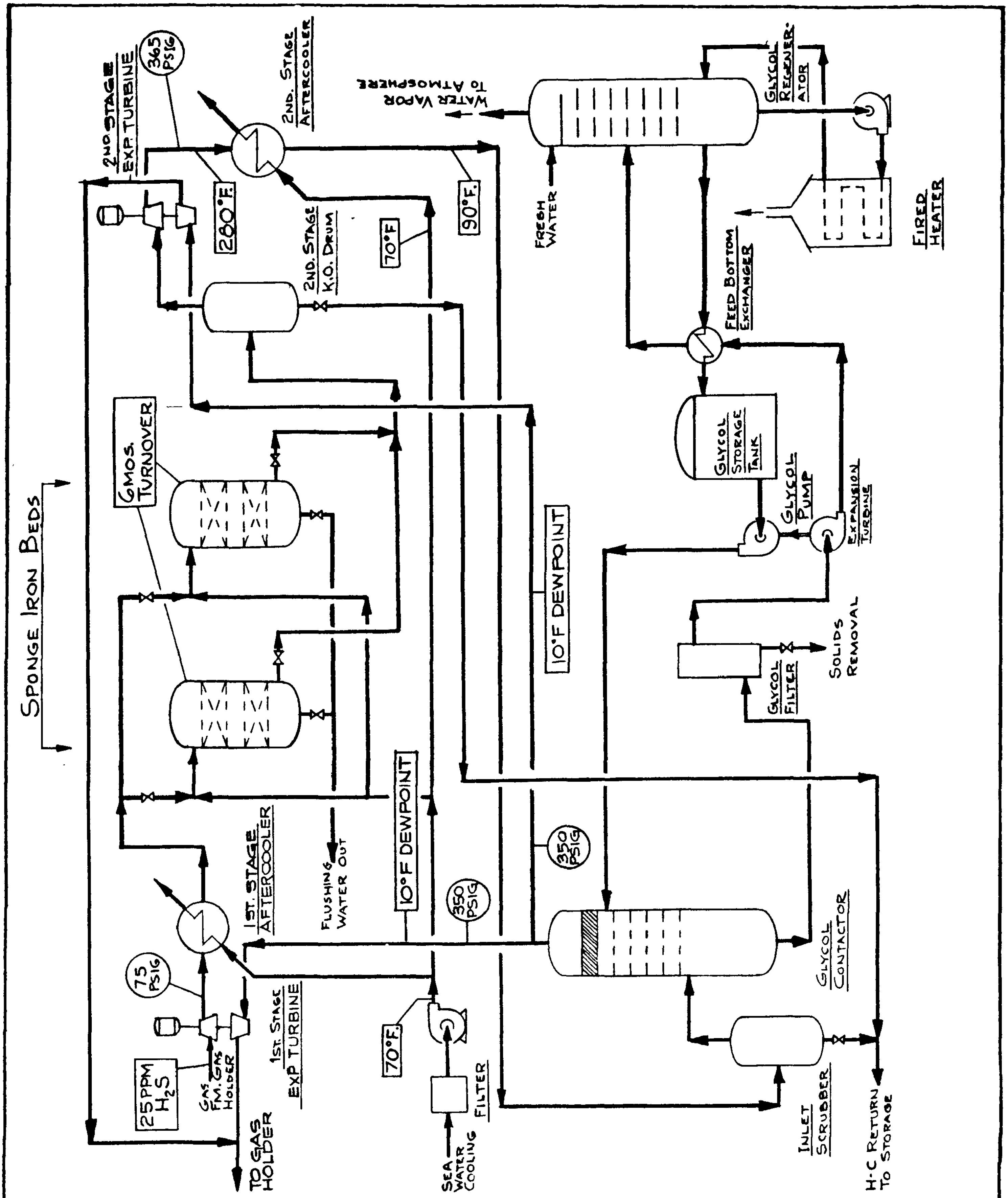

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	PLANT	Contract #68-02-2838		
	LOCATION	Treating Unit with IFR Tankage		

9.3 PIPING ARRANGEMENTS

Vapor collection and blanket gas distribution piping has been separately estimated and modulated for each vapor control system considered in this study. Low operating pressures and high transfer rates have created large, thin walled ducting up to 80" in diameter. Estimates have been based upon 1/4" steel wall thicknesses for this low-pressure ducting in sizes 6" and larger except in Case VII. Here 3/16" thicknesses have been estimated for additional flue gas errosion allowances, as discussed under Case VII paragraph 5.9. Mitred elbows and plate flanges are used in sizes 14" and larger. These lines are routed in pipeway locations so that internal detonations will cause the least amount of damage. Where longitudinal weld seams are used, a continuous weak (rip) seam can be directed upwards, or tilted to the least vulnerable direction. All vapor collection lines are sloped down to closed drain boots where condensations can be manually drained upon high level alarm signals in a centralized control room. Drains flow by gravity through a closed pipe line to the API separator without intermediate emissions, or by pumps from dock and beachhead locations.

Refer to drawings 153-1-13, -14, -15, -16, -19, -20, and -23 for typical piping arrangements. The only piping that needs insulation is that in which condensates from refrigerators are pumped. Here it is important that the flashing of liquid does not occur before the cold condensates are dispursed into main terminal transfer headers. All piping, other than waste water, has been estimated as being above ground.

Water seal pots and drain boots are totally enclosed vessels which automatically or manually drain through closed piping to the API separator in all except Cases I and IA. Three-inch seals are maintained by conventional level controls and continuous water circulation in each vessel.

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11.0 ABBREVIATIONS AND CONVERSIONS

Abbreviations used in this report are defined below in English units:

API = American Petroleum Institute (degree of density)
B/CD= barrels (42 gallon) per calendar day
BPH = barrels (42 gallon) per hour
Btu = British thermal unit
bbls= barrels (42 gallon)
DWT = dead weight tons
F.O.= fuel oil
fps = feet per second
ft. = feet
GPM = gallons per minute
KWH = kilowatt-hour
M = thousand
MM = million
osi = ounces per square inch
Part= particulates
PCV = pressure control valve
PSV = pressure safety valve
ppm = parts per million
psf = pounds per square foot
psia= pounds per square inch absolute
psig= pounds per square inch gage
RVP = Reid vapor pressure
SCFH= standard cubic feed per hour
ST/Y= short tons per year

Ounces, pounds, and short tons are Avoirdupois weights.

Applicable English to Metric conversion factors are:

barrel = 0.159 cubic meters

Btu = 0.252 kilogram - calories

short tons = 0.907 metric tons

feet = 0.305 meters

miles = 1.609 kilometers

gallons - 3.785 liters

ounces per square inch = 4.394 grams per square centimeter

pounds = 453.6 grams

pounds per square foot = 488.3 grams per square meter

pounds per square inch = 70.30 grams per square centimeter

standard cubic feet (at $60^{o}F$) = .0268 standard cubic meters (at $0^{o}C$)

cubic feet = .0283 cubic meters

TECHNICAL REPORT DATA
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1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Emission Control Technology for Marine Terminals Handling Crude Oil and Gasoline		5. REPORT DATE April, 1978 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Don M. Gammell		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Robert Brown Associates 500 East Carson Plaza Drive Carson, California 90745		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-2838
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED 14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT

This report presents results of a study which developed basic background information on emission control systems for a hypothetical deep water marine terminal handling crude oil and an inland marine terminal handling crude oil and gasoline. The study includes comparative cost analysis for alternative emission control systems together with comparable safety and reliability analysis for both marine terminal modules.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Control Methods Hydrocarbons Tankers and Barges Storage Tanks	Air Pollution Control Hydrocarbon Emission Control Organic Vapors Mobile Sources	

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE