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cost-effectiveness of hydrocarbon emission controls in refineries from crude oil receipt to product dispatch

Prepared by the CONCAWE Air Quality Management Group's Special Task Force on Refinery Hydrocarbon Emission Control Cost-effectiveness (AQ/STF 30)

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SUMMARY

CONCAWE has recognised that, despite the relatively small contribution to hydrocarbon emissions in Europe arising from petroleum refining and distribution, there is need for documentation on control techniques applicable in these sectors, with an assessment of costs. The distribution sector was covered in CONCAWE Report No. 85/54 (1) and the present report covers oil refining from crude receipt to product dispatch. Data are presented showing emission sources, the base case hydrocarbon emission, a control technique, the total investment, the annual operating cost and the cost-effectiveness of the control.

Base case refinery emissions, in terms of equipment now in use and its state of maintenance, and hence the present efficiency of hydrocarbon retention, vary considerably from place to place depending on local regulations and engineering practice. Partly for this reason, it was decided to base the study on a hypothetical 100,000 Bbl/CD (5 Mt/yr) refinery. This represents about 1% of present refining throughput in Western Europe.

The sources of hydrocarbon emissions considered are:

- crude oil and relevant product or component tankage at the refinery;
- road, rail and water transport loading;
- refinery process plant fugitive emissions and waste water treatment;
- crude oil tanker ballasting (at refinery or associated terminal).

Base case emissions are calculated for all the above sources. Techniques for further control are introduced, effectiveness assessed, and costs assigned. All equipment chosen is the best commercially available, proven in service, and can be retro-fitted.

Ranking emission control techniques in decreasing order of cost-effectiveness, measured as the annual cost per tonne of additional hydrocarbon retained in the system, shows the following:

1. formal programmes of monitoring and maintenance for control of fugitive emissions from refinery process plant have a cost-effectiveness of $US 100 per tonne;

2. provision of floating covers for waste water separator bays costs about $US 460 per tonne of emission reduction;

3. fitting rim mounted secondary seals in crude, feedstock and product tanks with external floating roofs has a cost-effectiveness in the range of $US 600 to $US 2840 per tonne;

4. the use of vapour recovery units at road loading gantries, with or without capture of vapour returned from service station tank filling, has a cost-effectiveness of $US 1,000 to $US 1,560 per tonne of hydrocarbon recovered, respectively.

Vapour recovery units for rail, barge and ship loading cost from $US 3,760 to $US 8,500 per tonne, suggesting a very low priority for implementation. The reason for the low cost-effectiveness relative to road loading is the infrequent use of larger capacity units.

For crude receipt, the changeover to segregated ballast with tanker fleet renewal over time (prescribed in the MARPOL 73/78 Convention) has the side effect of reducing hydrocarbon emissions at crude oil discharge locations.

If all the technology discussed in this report (excluding the crude tanker ballasting case) were applied in all refineries in Western Europe, the net effect would be a reduction of about 140 kt/yr of hydrocarbon emissions or only about 1.4% of the total anthropogenic hydrocarbon emissions in Western Europe; the annual cost would be about $US 170 million.

1. INTRODUCTION

Increasing emphasis has recently been placed on volatile hydrocarbons as atmospheric pollutants, particularly through their role in photochemical reactions. Scope for improved control over hydrocarbon emissions from stationary sources has become a matter for investigation and debate by regulatory bodies throughout Europe. It has been estimated that annual non-methane hydrocarbon emissions in Europe total some 20 million tonnes, about half arising from natural sources and half being anthropogenic (2). Among the latter, the major sources of emission are solvents (40%), and transportation (38%), with emissions from petroleum refineries and product distribution facilities accounting for only about 8% or 800,000 tonnes per year.

Despite the relatively small size of the petroleum industry contribution, CONCAWE has foreseen the need for reference documents summarising the control techniques applicable to volatile hydrocarbon sources in refineries and product distribution, together with an assessment of costs relative to the achievable hydrocarbon emission reductions. This report addresses refinery emissions from crude oil receipt to product dispatch. CONCAWE Report No. 85/54 (1) covers product distribution.

In these two reports, hydrocarbon emission estimates and the cost of controls are based on a hypothetical refinery of 100,000 barrels per calendar day (Bbl/CD) capacity, and its associated distribution system for motor gasoline through to car refuelling, and for sales naphtha (petrochemical feedstock) to bulk customers. This system is devised as a microcosm of the Western European oil industry, representing 1% of the present oil processing and distribution requirement of some 500 million tonnes oil products per year. For simplicity this report assumes that crude oil and other feedstocks are delivered directly to the refinery by sea.

The currently used equipment for control of hydrocarbon emissions is defined, and estimates of hydrocarbon emissions are presented, for all types of source from reception of crude oil and other feedstocks in the refinery tank farm, through to dispatch from the refinery. It is recognised that current practice and regulatory requirements differ from country to country and to some extent from site to site; the defined controls are however, considered to be broadly representative of present European practice.

Additional emission control techniques and equipment are selected for each source on the basis that they are proven in service, possible to retrofit, and of high retentive efficiency. Alternative types of equipment are not discussed although they do exist in many cases. The technical merits of, for example, different designs of floating roof secondary seal or vapour recovery equipment are dealt with in CONCAWE Report 85/54 (1).

The extent of hydrocarbon emission reduction to be expected with the chosen technique is estimated, and costs for application have been developed. Finally, a cost benefit relationship is derived, based on gross annual cost including capital and maintenance allowances, for each of the chosen control techniques. This provides a basis for rational selection of those sources of hydrocarbon emission within the petroleum industry which merit the highest priority for control measures when required.

The hydrocarbon emission estimates, and the costs for control equipment and techniques, are subject to wide margins of variation; they must not be assumed to be applicable to any particular site. They are intended for general guidance, and no specific level of precision is assigned to them. However, the calculation methods used have general validity and can be applied along with site specific cost estimates, to provide more rigorous assessments of schemes for improvement of hydrocarbon emission control in actual refinery systems.

2. BASIS FOR STUDY

2.1 DESCRIPTION OF HYPOTHETICAL REFINERY

2.1.1 Background

A hypothetical refinery is used as a basis for the present study, and is derived from an actual refinery in Europe. The process scheme and unit capacities were selected to meet the prescribed yield pattern, with specific reference to gasoline and sales naphtha (petrochemical feedstock) production. The throughput is 100,000 Bbl/CD (nominally 5 million tonnes per year).

The refinery is assumed to have an associated crude receipt facility and an appropriate balance of all practical routes for product dispatch by water, pipeline, road and rail.

2.1.2 Process scheme

The refinery is assumed to operate on a crude oil slate consisting of about 50% North Sea (low sulphur, Forties or similar) and 50% Arab light (high sulphur), plus 5% each of imported residue and condensate, to produce 30% vol motor gasoline and 8% vol sales naphtha (petrochemical feedstock). The volume yield of gasoline was derived from the Salomon Associates Inc. study (3). It is recognised that gasoline production in 1986 is closer to 25 vol % than 30 vol % of total throughput, but the higher number was used for this study because this is the direction in which the industry is moving. This choice does not affect in any way the cost-effectiveness numbers derived in the report, but it does result in an over-estimate of current hydrocarbon emissions from the petroleum industry in Western Europe. The gasoline is made to Eurograde specification. There is no production of light solvents, high octane aviation gasoline or of military jet fuel (JP-4). The process units required are shown in Table 1.

2.1.3 Crude oil reception

Crude oil is delivered by ocean going tankers in the range 70,000 to 150,000 dwt, with an average parcel size of 100,000 tonnes. Oil awaiting processing is stored in external floating-roof tanks, listed in Table 2 along with the details of relevant component and product tankage.

2.1.4 Tank farm

The refinery is of the integrated process type with minimal intermediate storage apart from naphtha product for catalytic reformer feedstock. In order to exclude water, the reformer feed tanks are of cone roof construction equipped with pressure vacuum valves, and are assumed to be gas blanketed.

All other tanks for products up to the kerosine boiling range are of conventional external floating roof construction with primary seals only; they are assumed to be well maintained though not necessarily in perfect condition.

Kerosine, gas oil and heavy fuel oil product tanks have been excluded from this study, as in all these cases the vapour pressure is extremely low and there are no significant hydrocarbon emissions. (By way of example, emission factors, calculated by the method in VDI-3479, (4) for gas oils are only one hundredth of the factor for crude oil). LPG is stored in enclosed pressurised or refrigerated tankage and also has no significant emissions. For the same reasons, none of these products need to be considered in the downstream dispatch facilities.

The tanks of significance in the estimation of present and future hydrocarbon loss to atmosphere are listed in Table 2, which shows the numbers, sizes, and construction of the tanks, and also the assumed properties of the contents in each group. The refinery tank farm capacity and distribution of tank duties and sizes is little affected if different distribution routes are required.

The current levels of hydrocarbon emissions from tanks, the measures to reduce these, and the possible future levels, are considered in Section 3.1.

2.1.5 Waste water treatment

Oily waste water requiring treatment before discharge includes process water from crude oil distillation unit desalters and wash water from the fluid catalytic cracker as the largest single continuous sources. There will also be tank drainings, oily area surface runoff and ballast water from product tankers, all of these being intermittent flows. The treatment system assumed is an uncovered API separator, secondary treatment e.g. flotation/flocculation, and biological oxidation. The secondary treatment processes produce no significant hydrocarbon emission.

This system is required to handle up to 400 m^3/h in normal conditions, with peak storm flows up to double this figure. The consequences in terms of potential emissions and the means and costs for containing them, are examined in Section 3.4.

2.1.6 Loading and dispatch facilities (motor gasoline and sales naphtha)

Dispatch of gasoline from the refinery uses four modes of transport:

- by pipeline (29%). Since this is a closed system, it is essentially emission-free, subject only to very small fugitive losses;

- by water (32%). Ship movements are handled on one jetty, with a parcel size of up to 5,000 tonnes, and an overall loading rate of 1,200 m^3/h (2 arms, 600 m^3/h each). Barge loading is handled separately, loading parcels of up to 2 000 tonnes, at rates up to 450 m^3/h;

- by rail car (9%). The assumed installation is used for top loading of two rail cars at any one time, with a maximum instantaneous filling rate of 500 m^3/h. The tank cars are of nominal 50 tonnes size (approximately 60 m^3) and are loaded in 15 minutes via 6 inch or 8 inch diameter loading arms;

- by road tanker (30%), for delivery direct to retail outlets. The road vehicles are of 30 m^3 (approx. 25 tonnes) capacity and can be loaded in 20 minutes. There are four loading points, each with three loading arms for top loading, and the maximum overall transfer rate is 20,000 l/min (1,200 m^3/h instantaneous). The maximum rate per loading arm is 2,500 l/min.

Naphtha has a similar dispatch system, but as shown in Section 3.5 is an unimportant source of emissions due to the means of dispatch and the smaller quantities involved.

2.2 ASSOCIATED HYPOTHETICAL DISTRIBUTION NETWORK

Motor gasoline is the only volatile refinery product manufactured in sufficient quantity to give rise to significant hydrocarbon emissions during distribution and storage at petroleum industry facilities downstream of the refinery.

A recent CONCAWE Report, No. 85/54 (I) is devoted to the quantification and control of hydrocarbon emissions from gasoline storage and distribution. It gives the whole picture for emissions downstream of the refinery.

The Report sets up a hypothetical gasoline distribution network, representative of typical European conditions, to move the 1,740,000 m^3/yr of gasoline produced by the hypothetical 100,000 Bbl/CD refinery of the present report to 1450 1200 m^3/yr service stations. Thirty per cent of the gasoline is delivered directly to nearby service stations from the refinery. The remaining seventy per cent is delivered to the more distant service stations via seven marketing installations, one large (500,000 m^3/yr), two medium (200,000 m^3/yr each) and four small (80,000 m^3/yr each). Gasoline transport from the refinery is by pipeline to the large terminal, by ship/ocean-going barge to both medium terminals, by inland waterway barge to two small terminals and by rail to the other two small terminals. Gasoline is delivered to all service stations by road vehicle.

2.3 COST BASIS

Investment estimates are based on project implementation in the second quarter of 1986 at a Netherlands location. The estimates are based on vendor quotations plus 10% for owner engineering, an allowance for associated offsite work if appropriate and a 25% contingency allowance and are given in US dollars (exchange rate 2.5 Dutch guilders/$US). Cost estimates are for guidance only. To determine the feasibility and cost-effectiveness of any proposed project, a detailed estimate fully reflecting project specifics, implementation schedule and local requirements must be made.

The annual operating costs assume a 25% charge on total investment to take into account depreciation and return on investment. Annual maintenance costs are taken as 4% of total investment and annual property overheads and insurance costs are taken as 1.2% of investment. Operating labour cost, including all benefits, is assumed to be $US 40,000/man-year. Electric power cost is taken as $US 60/MWh.

The cost-effectiveness of each control option is determined by dividing the annual operating cost by the reduction in hydrocarbon emission achieved.

No credit is taken for the value of the hydrocarbon recovered. The purpose of this report is to provide a ranking of control techniques by cost-effectiveness. The value of the hydrocarbon recovered does not affect this ranking.

3. HYDROCARBON EMISSION CONTROLS AND THEIR COST EFFECTIVENESS

3.1 EMISSIONS FROM REFINERY TANKAGE

3.1.1 Introduction

For the calculation of the hydrocarbon emissions from the refinery storage facilities, specified in Section 2.1, and Table 2, use has been made of officially published equations. These equations will be identified in the relevant sections below. It should be noted that the applied method does assume well maintained storage tanks and auxiliary equipment.

In Table 2 details are given that are applied for the individual hydrocarbon emission calculations.

Table 3 shows the base case hydrocarbon emissions of the total refinery storage and handling facilities for crude oil receipt, gasoline blending components, gasoline final grades and sales naphtha.

Table 4 shows the controlled hydrocarbon emissions for the same facilities.

Table 7 provides a summary of refinery tankage emissions, the cost of controls and the cost effectiveness.

3.1.2 Hydrocarbon emissions from cone roof tanks (without internal floating covers)

Products that are stored in cone roof tanks are residue and reformer feed. These tanks are subject to displacement, withdrawal and breathing emissions.

The working emissions for the reformer feed tanks have been put to zero in view of the very limited number of tank level movements.

3.1.2.1 Working emissions (displacement plus withdrawal emissions)

In an EPA publication (5) the following equation has been given for the calculation of the displacement plus withdrawal emissions from cone roof tanks, which will be referred to as the working emissions.

$$E_{wo} = 4.45 \times 10^{-3} \times TVP \times K_n$$

where:

E_{wo} = Working emissions (liquid equivalent) as percentage of the liquid volume throughput

TVP = True Vapour Pressure of the liquid, kPa

K_n = Turnover factor (dimensionless) see Fig. 1.

The values of the relevant tanks have been given in Table 3.

3.1.2.2 Breathing emissions

An equation as given in a VDI Publication (4) has been simplified to give the following equation which may be used to estimate total breathing emissions for operational cone roof tanks fitted with P/V valves:

$$E_b = 4.33 \times 10^{-4} \times TVP \times M_v \times V_S \left(\frac{P_1}{T_1} - \frac{P_h}{T_h}\right)$$

where:

E_b = Breathing emissions (liquid equivalent) in m^3/yr

TVP = True vapour pressure of liquid in kPa

M_v = Molecular weight of product vapour, kg/kmol

V_S = Tank vapour space average volume, m^3

P_1 = Lower P/V valve setting in kPa absolute

T_1 = Mean minimum annual temperature in vapour space, °K

P_h = Higher P/V valve setting in kPa absolute

T_h = Mean maximum annual temperature in vapour space, °K

Paint factor = 1.1 (Aluminium silver paint)

The values for the relevant tanks have been given in Table 3.

Assumptions made for these calculations are:

- atmospheric pressure of 101.3 kPa;
- saturation level in vapour space of 60%;
- density of emitted hydrocarbon vapour in liquid form at storage temp. is 600 kg/m^3;
- P/V valve settings are - 0.6 kPa and + 2.0 kPa.

3.1.3 Hydrocarbon emission from external floating roof tanks

Open top vertical cylindrical tanks, fitted with floating roofs have a high vapour retention efficiency. This is because the liquid product air interface is virtually eliminated by the floating roof.

A flexible seal provided to cover the annulus between the floating roof and tank shell is to inhibit evaporation and emission of hydrocarbon vapour.

The major factor causing the vapour emissions normally occurring from floating-roof tanks, is the effect of the wind, although these emissions are usually at a relatively low level.

Evaporation is promoted if the wind blows down through gaps between the seal and the tank shell, and also may be promoted by wind eduction.

Such evaporation losses are defined as standing storage vapour emissions and may be estimated as described in Section 3.1.3.1.

There will also be losses by evaporation from a film of hydrocarbon liquid adhering to the tank shell following pump-out of product.

These, which are defined as withdrawal emissions, may be estimated as described in Section 3.1.3.2.

3.1.3.1 Standing storage emissions

API Bulletin No. 2517, published originally in 1962, has been revised to take into account recent developments in technology and efficiency evaluation techniques. A second edition (February 1980) has been issued (6), giving an improved method to estimate vapour emissions.

The following equation is the metricated equivalent of the revised API equation.

$$Kg_s = 1.488\ K_s\ (2.237\ V_w)^n\ P\ D_t\ M_v\ K_c$$

where:

Kg_s = Standing storage emissions, kg/yr

K_s = Seal factor, see Table 5

V_w = Average wind speed (2.8 m/s)

n = Seal-related wind speed exponent, see Table 5

P = Vapour pressure function (dimensionless)

The vapour pressure function P, is calculated from the formula

$$P = \frac{\frac{TVP}{AP}}{\left[1 + \left(1 - \frac{TVP}{AP}\right)^{0.5}\right]^2}$$

where:

TVP = True Vapour Pressure at average storage temperature, kPa

AP = Average atmospheric pressure at tank location, 101.3 kPa

D_t = Diameter of the tank, m

M_w = Average molecular weight of hydrocarbon vapour, kg/kmol

K_c = Product factor for crude oil = 0.4
for refined products = 1.0

The values for the relevant tanks have been given in Table 3.

A shoe-mounted mechanical seal has been assumed as primary seal.

To control the hydrocarbon emissions from floating roof tanks it has been assumed that rim-mounted secondary seals will be used.

The emissions from these tanks, with secondary seals, are given in Table 4.

3.1.3.2 Withdrawal emissions

In accordance with procedures given in API Bulletin 2517 (6), withdrawal emissions may be calculated from equation (metric equivalent):

$$Kg_w = \frac{0.004 \times T_p \times C_f \times D_1}{D_t}$$

where:

Kg_w = Withdrawal emission, kg/yr

T_p = Average throughput, m^3/yr

C_f = Average clingage factor see Table 6, $m^3/1000\ m^2$

D_1 = Average product liquid density, kg/m^3

D_t = Diameter tank, m

The values for the relevant tanks have been given in Table 3.

3.1.4 Total uncontrolled hydrocarbon emissions

An estimate of the total uncontrolled hydrocarbon emissions per year of the storage facilities for crude oil/feedstocks, gasoline blending components, final gasoline products and sales naphtha within the hypothetical 100,000 Bbl/CD refinery is obtained, as the sum of the cone roof tank and floating roof tanks emissions, as derived in Sections 3.1.2.1, 3.1.2.2 and 3.1.3.1, 3.1.3.2. The values per individual component are given in Table 3.

3.1.5 Reduction of emissions

The hydrocarbon emissions as calculated in the Sections 3.1.2, 3.1.3 and summarised in Section 3.1.4 can be reduced by applying the following criteria:

- select most suitable type of storage tanks;
- apply sound maintenance principles;
- introduce proper operation methods.

In addition to these criteria the hydrocarbon emissions can be further controlled by providing the storage tanks with:

- internal floating covers, for cone roof tanks;
- secondary seals, for external floating roof tanks.

3.1.5.1 Internal floating covers for cone roof tanks

Within the hypothetical refinery the usage of cone roof tanks has been restricted to:

- products/components with a low vapour pressure
- product/component requiring inert gas blanketing

Tanks that are considered to contribute to the total hydrocarbon emission are those for the storage of residue and naphtha for reformer feed.

Providing these tanks with internal floating covers will result in the following reduction of hydrocarbon emission; use has been made of the equation published in API-Publication 2519, converted to metric units (7).

Standing storage emission:

$$Kg_s' = \left[(K_r D_t) + F_f + F_d\right] P M_v K_c$$

where:

Kg_s' = Standing storage emissions, kg/yr

K_r = Rim seal emission factor (kmol/m yr), see (a)

D_t = Tank diameter (m)

P = Vapour pressure function (dimensionless), see Section 3.1.3.1

F_f = Total deck fittings emission factor (kmol/yr), see (b)

F_d = Deck seam emission factor (kmol/yr), see (c)

M_v = Average product vapour molecular weight (kg/kmol)

K_c = Product factor (dimensionless), see Section 3.1.3.1.

(a) Rim seal emission factors (K_r)

Rim seal type	K_r kmol/m yr Average condition	K_r kmol/m yr Tight fitting
Vapour-mounted primary only	9.97*	8.33
Liquid-mounted primary only	4.46	3.87
Vapour-mounted primary plus secondary	3.72	3.42
Liquid-mounted primary plus secondary	2.38	1.79

* If no specific information is available this value can be assumed to represent the typical system in use.

(b) Total deck fitting emission factor (F_f)

For application in the metric equation, particularly when there is no information on the type and number of deck fittings, a typical total deck fitting emission factor (F_f) in metric units may be obtained by the formulae:

- Tanks with self-supporting fixed roofs:

  Bolted deck $F_f = 0.1113\ D_t^2 + 1.176\ D_t + 47.72$

  Welded deck $F_f = 0.0644\ D_t^2 + 1.176\ D_t + 47.72$

- Tanks with column-supported fixed roofs:

  Bolted deck $F_f = 0.2348\ D_t^2 + 2.072\ D_t + 60.87$

  Welded deck $F_f = 0.1880\ D_t^2 + 2.072\ D_t + 60.87$

where D_t = Tank diameter (m).

These formulae were derived from the formulae appearing in Figs. 1 and 2 in the API publication 2519 (7).

(c) Deck seam loss factor (F_d)

For a cover which is made of bolted sections a metric value of F_d can be estimated from the formulae:

$$F_d = 0.506\ S_d\ D_t^2$$

where

$$S_d = \frac{L_{seam}}{A_{deck}} \quad \begin{array}{l} (L_{seam} = \text{total length of deck seams m}) \\ (A_{deck} = \text{area of the deck } m^2) \end{array}$$

Alternatively the value of F_d may be estimated from the following table which is the metric equivalent of data presented in Table 6 of the API Publication (7).

Continuous sheet construction	Typical deck seam length factor S_d (m/m^2)
1.25 m wide sheet	0.656*
1.83 m wide sheet	0.558
2.13 m wide sheet	0.459
Panel construction	
1.52 x 2.29 m panels	1.083
1.52 x 3.66 m panels	0.919

* If no specification information is available, this value can be assumed to represent the most common/typical bolted deck currently in use.

The values for the relevant tanks have been given in Table 4.

Withdrawal emissions

$$Kg_w' = \frac{0.004\ T_p\ C_f\ D_l}{D_t}\left[1+\left(\frac{N_c\ F_c}{D_t}\right)\right]$$

where:

Kg_w' = Withdrawal emission, kg/yr

T_p = Annual net throughput, m^3/yr

C_f = Clingage factor, m^3/1000 m^2, see Table 6

D_l = Average liquid stock density at average storage temperature, kg/m^3

D_t = Tank diameter, m

N_c = Number of tank roof supporting columns

F_c = Effective column diameter, m

The values for the relevant tanks have been given in Table 4.

3.1.5.2 Secondary seals for external floating roof tanks

The hydrocarbon emission reduction effect can be estimated using the same formula as given in Section 3.1.3.1.

The factors that are influenced are K_s and n, for which values are given in Table 5.

As secondary seal a rim mounted construction has been assumed on top of a mechanical shoe mounted primary seal.

The values for the relevant tanks have been given in Table 4.

3.1.6 Costs

3.1.6.1 Cost of internal covers in cone roof tanks

The costs below refer to aluminium deck type covers. Tank cleaning costs are not included.

Tank diameter m	Material costs $US	Erection costs incl. freight $US	Total capital $US
10	7,600	4,400	12,000
15	11,700	6,000	17,700
20	17,500	8,400	25,900
25	23,800	10,100	33,900
30	30,700	12,000	42,700
36	40,300	14,000	54,300

3.1.6.2 Cost of secondary seals for external floating roof tanks

Provision of rim mounted secondary seals is estimated to cost $US 140 per metre of circumferential distance. Tank cleaning costs are not included.

3.2 EMISSIONS FROM BALLASTING CRUDE OIL TANKERS

When crude oil tankers have discharged cargo at a refinery, it is standard practice to clean cargo tanks by crude oil washing and take on ballast water into some of the empty compartments so that the ship's draft and trim are safe for normal navigation on the return voyage to the loading port. As ballast water is pumped into the selected tanks, hydrocarbon vapour evolved from the oil originally in the cargo space will be displaced, mixed with inert gas or air. Methods of estimating the amount of hydrocarbon so displaced, in various conditions, are given in API Publication 2514A, "Atmospheric Hydrocarbon Emissions from Marine Vessel Transfer Operations" (second edition), September 1981, (8).

The situation will be changed by the provisions of the International Convention for the Prevention of Pollution from Ships 1973 as modified by the 1978 protocol (MARPOL 73/78). This convention, now in force, was introduced not to prevent atmospheric pollution, but to limit the amount of oil reaching the seas through dirty ballast discharges. Certain provisions are in practice at variance with the need to reduce hydrocarbon loss to air.

The relevant features of MARPOL 73/78 are:

1) that all new ships, and certain converted vessels, in the size classes normally considered as crude oil carriers, shall have segregated ballast systems in which there will be no contact of oil with ballast water;

2) that existing vessels must either be converted for segregated ballast operation, or be provided with cargo tank cleaning procedures using crude oil washing.

An interim provision in MARPOL 73/78 allows operation with "dedicated clean ballast" for a limited period, but is not of significance in this context; the practical effect is the same as fully segregated ballast operation.

Consequent on the first of these provisions, a significant and increasing proportion of crude oil carriers will have a segregated ballast system, and thus should not emit any hydrocarbon during reballasting. Available information indicates that some 25% of crude oil carriers, either newly built or modified, are now operated in this manner. The economics of ship operations do not however, suggest any great likelihood that more existing vessels will be modified. It is not possible to predict how long it will be before all existing vessels are replaced, but it could reasonably be expected that few non-segregated ballast vessels will remain in service beyond the mid-1990s.

The crude oil washing alternative allowed in the second provision will not help reducing hydrocarbon emissions to air. Crude oil washing leads to substantial generation of hydrocarbon vapour in the cargo space which is being cleaned. It is however, effective in reducing the amount of liquid oil which may remain in cargo tanks and eventually come into contact with ballast water. Unfortunately, API 2514A does not contain any suggestions on estimation of emissions when a ship is ballasted after crude oil washing, and no published data from any other source has been discovered. Limited experimentation by one oil company suggests that vapour evolution in the course of crude oil washing of ballast tanks in a 100,000 dwt tanker would be of the order of 40-50 tonnes. (This figure is about two thirds of that expected if crude oil washing resulted in complete hydrocarbon saturation of the vapour space). The potential emission from the hypothetical refinery, with 75% of crude oil ships being operated in this manner, is around 1,500 tonnes per year (0.03% weight on crude oil throughput). This figure will decrease steadily as more new ships with segregated ballast come into service.

Some vessels are equipped so that the following routine can be practised at the discharge port.

1) Pump out cargo from compartments nominated to receive ballast;

2) crude oil wash these compartments while others commence discharging ashore;

3) load ballast, and displace vapour to compartments which are still discharging crude oil;

4) complete tank washing and purge vapour spaces with inert gas as the ship proceeds on its ballast voyage.

Reasonable care in this mode of operation ensures that no immediate and significant vapour emission is associated with ballasting. Although additional hydrocarbon vapour is generated, it is not emitted until the vessel is at sea on its ballast voyage. In such conditions recovery of vapour is unlikely to be practicable.

In the event that displaced vapours from ballasting operations were to be discharged to shore for recovery, it would be necessary to size the vapour recovery unit (VRU) for up to 5,000 m^3/h. The discrepancy in size between this and a VRU for gasoline cargo loading is such that it would almost certainly be necessary to provide a separate unit; in many instances separate provision would be required in any event on account of geographical separation of crude and product jetty systems.

The capital cost of such an installation (extrapolated from data in CONCAWE Report 85/54 (1) is estimated at around $US 3.35 million. Total annual costs including maintenance and operation are calculated to be approximately $US 1.0 million (see table below).

Capital cost based on a 1200 m^3/h vapour recovery unit

	k $US
Vapour return arms/jetty modification	400
VRU pipework connections (ca. 500m from jetty)	90
VRU purchase and install	320
Vapour return mods. to vessels	250
Contingency 25%	265
	1325

Cost scale-up factor is $F^{0.6}$ where F is throughput factor

VRU's purchase and installation (2 x 2500 m^3/h units)	992
Remainder of installation	2362
Total capital cost	3354

Annual operating cost

Capital charge (25%)	838
Maintenance, insurance etc. (5.2%)	174
Utilities and manning	5
	1017

90% recovery of hydrocarbons emitted, assuming a decreasing scale over 10 years, offers a cost-effectiveness of about $US 1500/tonne. Although this is superficially attractive, the calculation procedure used above may seriously underestimate the cost, particularly for maintaining and keeping operable a unit which even initially will have a time utilisation of less than 3%. In addition, the pipework cost is probably underestimated as several jetties may need to be served, some at considerably greater distance than 500 m from the recovery unit.

3.3 FUGITIVE EMISSIONS FROM REFINERY PROCESS AREAS

Fugitive hydrocarbon emissions comprise all losses by leakage from equipment such as pump and compressor seals, valve stem packings, flanges and other minor sources. The total number of individual sources in a refinery can run to many thousands, and they are mainly concentrated in the process units.

The incidence of leakage is very variable, but once an individual leak has started the rate of loss can increase quite rapidly, especially from such sources as pump seals. It is possible to measure losses with some accuracy, for example by "bagging" potential sources, but this is an extremely laborious exercise; furthermore, the results give only an instantaneous picture of the total situation, and will be out of date very quickly. It is therefore usual to detect, and estimate the magnitude of leaks, by means of hydrocarbon vapour detectors. The prime objective is to identify mechanical components needing urgent maintenance, and to use broad categorisation of the magnitude of individual leaks to arrive at a total for the whole installation.

Large differences between installations, and from time to time at a given site, are to be expected. The extent of leakage depends heavily on the effort devoted to detection and the amount and quality of maintenance effort expended.

Factors developed during the comprehensive EPA/Radian study (8) in the USA indicate a loss rate of 0.03% weight on crude oil throughput for the hypothetical refinery (Table 8). Other calculation methods indicate somewhat lower values than the EPA study. In a typical present day European refinery, with a conventional level of maintenance and no mandatory monitoring for leakage, the fugitive losses probably amount to about 0.025% weight on crude oil throughput. Limited recent work (unpublished) at two European refineries, using monitoring techniques now in routine use in the USA, confirms this figure. Wide variation can be expected. In West Germany, where more attention has been devoted to improving performance on fugitive loss prevention than in most other European countries, such losses are reported (1984/5) to be commonly at or below 0.01%. The required measures will include, for example, non-leaking pumps with single or double mechanical seals or magnetic couplings, recovery of losses, reduction of flanges or use of high performance gaskets, valve shaft sealing by bellows seals.

In the USA, there are detailed Federal and State regulations on leak monitoring and maintenance programmes. A wide enough sample of information is not available to permit assessment of the quantitative improvement in fugitive losses obtainable by such formal programmes and even less to determine the extent to which increased inspection frequency can further reduce the losses. A subjective view is that a good monitoring and maintenance programme, whether or not formalised by regulatory rules, can contain fugitive emissions below 0.015% weight on crude oil throughput based on an annual inspection, with perhaps 0.006% achievable by a rigorous quarterly programme.

One example of a US programme (in Ohio) requires annual inspections for components in hydrocarbon liquid service, and quarterly for gas service. Special rules apply to defined hazardous materials such as benzene at high concentration, and in such cases monthly monitoring may be called for.

Cost data, adapted to the hypothetical refinery are as follows, based on the Ohio regulations and costs.

> Initial investigation including identification and recording for the complete system and preliminary maintenance, would cost about $US 110,000.
>
> Subsequent monitoring, including limited repair such as tightening valve packing which might be handled by the inspection crew, costs up to $US 70,000 per year, at $US 1.50 per component checked.

It has not been possible to obtain any cost benefit analysis of this US system. Formal monitoring and maintenance programmes are required by law in order to achieve maximum environmental protection. The cost of determining whether or not such programmes are economically successful could not be justified by any company in such circumstances.

For the purposes of the present study, the somewhat incomplete evidence suggests that a regular monitoring and maintenance programme, not necessarily formalised to the extent found in the USA, will add some $US 70,000 to annual operating costs. This could result in an improvement in fugitive hydrocarbon emissions from 0.025% to 0.010% wt on crude oil throughput equivalent to an emission reduction of 750 t/yr for the hypothetical refinery.

The cost-effectiveness is of the order of $US 100 per tonne of potential loss reduction, which puts this type of effort at the top of the effectiveness rankings by a large margin. The ranking is, furthermore, relatively insensitive to any underestimates in cost, or to over-optimism about the amount of hydrocarbon saved within the system.

3.4 EMISSIONS FROM REFINERY WASTE WATER SEPARATORS

3.4.1 Estimation of hydrocarbon emissions from waste water separator

Process waste waters, cooling water, and rain runoff in a refinery are collected by one or more sewer networks. These sewers discharge into some form of oil/water separator. The most common type is a rectangular basin sized to provide sufficient residence time for all oil droplets larger than some specified size, to rise to the surface. A frequently used facility is the API gravity separator (10), designed to remove all oil droplets greater than 150 µ. The API design criteria restrict horizontal velocity to a maximum of 0.9 m per minute. A typical API separator might be 35 to 50 m long with a residence time of 40 - 60 minutes. The total width of the separator(s) is dependent on waste water flow, storm water handling facilities and spare basins needed for carrying out maintenance. In any event, refinery separators provide a large oil-covered surface from which hydrocarbon evaporation will occur.

The only recent calculation method in the literature for estimation of hydrocarbon evaporation from oil/water separators is by Litchfield (11). This method requires knowledge of:

- Influent hydrocarbon quantity
- The 10% distillation point (to provide volatility data)
- Waste water temperature
- Ambient temperature

It should be noted that neither wind velocity nor separator surface area, both of which would be expected to have some influence on evaporation, are included in this calculation method.

The Litchfield equation is:

$$\text{Loss} = -6.6339 + 0.0319x - 0.0286y + 0.2145z$$

where Loss is expressed as a volume % of inlet oil
x is ambient air temperature, °F
y is 10% distillation point, °F
z is waste water temperature, °F.

Unpublished 1979 CONCAWE refinery survey data show a median waste water temperature of 75°F (23.9°C), a median ambient air temperature of 55°F (12.8°C) and a median 10% distillation point of 325°F (162.8°C). While these temperature data appear reasonable, the 10% distillation point seems too high. 250°F (121.1°C) is considered a more typical value for the 10% distillation point of incoming oil and is used here. These parameters indicate a hydrocarbon loss of 3.9 vol % of the incoming oil.

Determination of the absolute amount of hydrocarbon lost requires knowledge of two parameters, the waste water flow and the concentration of hydrocarbon in the waste water entering the separator. The hypothetical 100 kBbl/CD refinery is assumed to have a waste water flow of 400 m^3/h containing 2000 mg/l of oil. Combining these values with the above 3.9 vol % loss gives a loss of 303 m^3/yr. This is equivalent to 200 t/yr, assuming a liquid density of 600 kg/m^3 for the evaporated hydrocarbon.

3.4.2 Separator covers

Hydrocarbon evaporation from oil/water separators can be substantially reduced by adding covers. There are two basic types of cover, fixed and floating.

3.4.2.1 Fixed covers

Fixed covers necessarily have a vapour space between the oil surface and the cover. There will be the potential for explosive vapours to build-up under the cover unless this space is inerted, which adds very considerably to the operating cost and is rarely practiced. Fixed covers can be steel plate, concrete slabs, rigid plastics or coated fabric. All have been used. The latter minimises missiles in the event of an explosion occurring. Other design considerations with plastic or fabric are compatibility with hydrocarbon vapours and avoidance of deterioration in sunlight. Fighting fires under fixed covers is difficult and hence fixed foam connections are recommended. A further substantial investment which can occur when adding a fixed cover is the need to replace travelling bridge oil/sludge scrapers with chain flight scrapers. This is necessary if the potentially explosive vapour space is to be kept to a minimum.

3.4.2.2 Floating covers

Floating covers come in two types: small (approx 5 cm diameter) plastic spheres or aluminium honeycomb slabs. Both types decrease hydrocarbon emissions while avoiding the major hazard of fixed covers, the potentially explosive vapour space.

Multiple small spheres have been tried in Europe with variable success. Major disadvantages are a tendency to get where they do not belong and difficulty in removing them for maintenance e.g. desludging of separator basins. The hydrocarbon emission suppression efficiency is lower for spheres than for interlocking slabs.

Interlocking slabs, each usually as long as the width of the separator bay and about 1.5 m wide, have been used with success in the USA. They avoid the above disadvantages of multiple spheres. By increasing the surface oil level by a few centimetres so as to cover the scraper boards, chain flight scrapers can still be used.

3.4.3 Cost of covers

Vendor quotes for the installed cost of floating slab covers for typical refineries are in the range 450 - 550 $US/m^2. Assuming the hypothetical 100 kBbl/CD European refinery has 400 m^3/h of waste water, then as a minimum a single 5m wide x 40m long separator would be required. In order to provide some spare capacity for storm flows and to cover for periods of maintenance/sludge removal, two bays each 5m x 40m would most probably be provided. The vendor cost for covering this two-bay separator would be about 200 k$US. The total refinery investment and operating costs are worked-up below:

Capital	k$US
Direct and indirect capital cost	200
Owners cost (10% of above)	20
	220
Associated offsite cost	Nil
Subtotal	220
Contingencies (25%)	55
Total Investment	275

Operating Cost	k$US/yr
Maintenance (4% of investment)	11.0
Property overheads & insurance (1.2% of investment)	3.3
Utilities	Nil
Annual capital charge (25% of Investment)	68.8
Total operating cost	83.1

3.4.4 Cost-effectiveness

Assuming that a floating slab cover will reduce hydrocarbon emissions by 90%, the hydrocarbon saved per year is 0.90 x 200 = 180 t. The cost efficiency of the cover is $US 83,100/180 t = 461 $US/t.

3.4.5 Parallel plate separators

Substitution of some type of parallel plate separator for the basin-type oil/water separator would be an alternative approach to reducing hydrocarbon emission. Parallel plate separators are generally covered and hence no hydrocarbon emission occurs. They frequently, however, have an open upstream basin or a grit trap and this would require covering. For a refinery with an existing basin type gravity separator, it is cheaper to provide covers than to replace the unit by parallel plate separators.

3.5 DISPATCH OPERATIONS FILLING EMISSIONS

Refinery dispatch facilities for gasoline are assumed to have throughputs and calculated base case hydrocarbon emissions as tabulated below:

	Throughput	Hydrocarbon Emissions During Loading	
	km^3/yr	Liquid Vol.%	t/yr
Ship/Ocean Barge	400	0.034	82
Barge Inland	160	0.052	50
Rail	160	0.061	59
Road	521	0.055	172

A description of these facilities is given in Section 2.1.6 and the emissions calculation procedures are shown in CONCAWE Report No. 85/54 (1) Sections 4.1.2, 4.3.2.2, 4.3.2.3, 4.3.2.4.

The application of Vapour Recovery Unit (VRU) technology to these dispatch facilities is also fully covered in Report No. 85/54 and data extracted from Table 7 of that report is given below showing VRU cost-effectiveness:

	Hydrocarbon Recovered t/yr	Total Investment k$US	Annual Operating Cost k$US/yr	Cost-Effectiveness $US/t
Ship/Ocean Barge	73	1511	468	6450
Barge (Inland)	44	1220	378	8510
Rail	52	623	196	3760
Road	153	751	239	1560

For naphtha dispatch, only rail and ship/barge modes have loading throughputs which justify assessment of hydrocarbon emissions. These are tabulated below and are so small that installation of an emission control technique would never be considered:

	Throughput km^3/yr	Hydrocarbon Emissions During Loading Liquid Vol.%	t/yr
Rail	46	0.02	6
Ship/Barge	186	0.018	22

4. RELATIONSHIP OF REFINERY EMISSIONS TO DISTRIBUTION EMISSIONS

Table 9 summarises the hydrocarbon emissions and cost-effectiveness of controls at the hypothetical 100 kBbl/CD refinery.

For comparative purposes Table 10, based on information presented in CONCAWE Report No. 85/54 (1), shows similar information on the distribution system associated with this refinery.

Fig. 2 provides in bar-graph form, a summary of the effect on Western European emissions of successively adding control options to both the refinery and distribution systems. The line graph in Fig. 2 shows the cumulative annual cost of these additions.

5. DISCUSSION AND CONCLUSIONS

The data developed on the hydrocarbon emission and the cost-effectiveness of controls for the various emission sources associated with a hypothetical 100 kBbl/CD refinery including crude receipt and product dispatch operations are summarised in Table 9. This shows the emission source, the base case annual hydrocarbon emission, a control technique, the total investment, the annual operating cost and the cost-effectiveness of the control.

The base case hydrocarbon emissions amount to about 3.5 kt/yr or about 0.07 wt% of the total refinery throughput, of which 0.03 wt% is from ballasting crude carriers and 0.04 wt% from all other sources. Refineries receiving crude oil by pipeline will nevertheless have an associated receiving terminal where equivalent emissions will occur.

Ranking the emission control devices in order of decreasing cost-effectiveness shows the following:

	$US/t
Refinery monitoring and maintenance program to control fugitive emissions	100
Covers on waste water separators	460
Rim mounted secondary seals on some external floating roof tanks	600 - 2840
Vapour recovery units on road loading gantries.	1000 - 1560

In addition, as a consequence of the MARPOL 73/78 Protocol requiring all new crude carriers to have segregated ballast tanks to minimise pollution of the sea, the emission of hydrocarbon vapours during ballasting will ultimately be eliminated.

As there are the equivalent of one hundred 100 kBbl/CD refineries in Western Europe, the base case hydrocarbon emission from processing, tankage and loading at refineries is some 200 kt/yr, or about 2% of the estimated total anthropogenic emissions (2). In addition, there are emissions of some 150 kt/yr associated with ballasting of crude oil carriers, which will be reduced to zero without further onshore control being required.

If all the technology applicable to refinery operations, as discussed in this report were applied at an annual cost of about $US 170 million the net effect would be a reduction of about 140 kt/yr of hydrocarbon emissions or only about 1.4% of the total anthropogenic hydrocarbon emissions.

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Ballasting Product Tankers and Sea Going Barges

It is assumed that the refinery will supply 400,000 m^3/yr of gasoline by ship and sea-going barge to medium-sized marketing installations. These large tank vessels will require ballasting at the receiving installation for their return voyage to the refinery.

The MARPOL 73/78 requirements for these vessels, which are assumed to be in the size range up to 30,000 dwt, will not bring about any change in current practice of significance to the present study.

It is appropriate to assume loading of 30% ballast into uncleaned compartments which previously carried 35 kPa TVP gasoline. API Bulletin 2514 A (8) does not address ballasting of product carriers, so the crude oil ship ballast calculations have been used as an approximation. The emission factor in these conditions is 1.4 pounds per thousand US gallons of ballast (approximately 0.17 kg/m^3), and the annual loss of hydrocarbon from this cause is about 20 tonnes (34 m^3) or 0.008 vol % on products handled.

It would be technically possible to recover this material up to say, 18 tonnes per year, by increasing the size of the VRU provided at medium size installations to allow for double the instantaneous vapour handling capacity. The total annual cost would increase by some $US 140,000. Cost-effectiveness of this plant extension is therefore not well ranked, at over $US 7,500 per tonne.

Inland waterway barges delivering to small installations are not ballasted.

Table 1: Process units in hypothetical refinery

	No. of Units	Total Capacity kBbl/Stream day
Crude oil distillation (with light ends unit and naphtha hydrotreater)	2	110
Vacuum distillation	1	43.5
Fluid catalytic cracking	1	25
Catalytic reformer	1	18
Gas oil hydrofiner	1	15
Thermal cracking (visbreaking)	1	10
Polymer gasoline unit	1	5
Merox sweetening (kerosine and FCC naphtha)	2	Note 1
LPG	1	400 t/d
Sulphur recovery	1	Note 1

Note 1: Capacity may vary significantly depending on type of crude feedstocks and severity of operations.

Table 2: Tankage for hypothetical refinery

Stored Material	Gross Capacity m^3	No. of tanks m^3	Tank gross m^3	dia m	type*	TVP kPa	Turnover km^3/yr	Product density kg/m^3
Crude oil	450000	12	37500	55	FR	34.0	5172	850
Condensate	26000	2	13000	30	FR	53.0	357	650
Residue	52000	4	13000	30	CH	0.7	255	980
Gasoline (sales product)	42000	7	6000	25	FR	35.0	1740	750
Naphtha (sales product)	12000	2	6000	25	FR	33.1	464	700
Cat. Reformer Feed	12000	2	6000	25	CB	14.6	-	720
Cat. Reformate	20000	2	10000	30	FR	22.3	943	750
Light Naphtha (SR gasoline)	6000	2	3000	20	FR	50.0	85	675
Heavy Cat. Cracked naphtha	6000	2	3000	20	FR	14.6	172	775
Light Cat. Cracked naphtha	12000	2	6000	25	FR	40.5	343	725
Poly gasoline	8000	2	4000	20	FR	32.1	172	800

*FR = External floating roof - single seal, shoe mounted
CH = Cone roof, heated
CB = Cone roof, inert gas blanketed

Table 3: Base case hydrocarbon emission from hypothetical refinery tankage

Source	Annual volume km³	Tank type *	Floating Roof Tank — Primary seal emission from: Standing storage kg/yr	With-drawal kg/yr	Total kg/yr	Cone Roof Tank — Emission from: Working kg/yr	Breath-ing kg/yr	Total kg/yr
Crude Oil	5,172	FR	78,310	10,269	88,579			
Condensate	357	FR	19,680	241	19,921			
Residue	255	CH				7,497	3,773	11,270
Gasoline Prod.	1,740	FR	33,105	1,605	34,710			
Sales Naphtha	464	FR	3,484	403	3,887			
Reformer Feed.	-	CR				-	10,454	10,454
Reformate	943	FR	6,674	735	7,409			
Light Naphtha	85	FR	12,074	89	12,163			
Heavy Cat. Cr. Naphtha	172	FR	2,787	207	2,994			
Light Cat. Cr. Naphtha	343	FR	11,366	310	11,676			
Poly Gasoline	172	FR	6,807	214	7,021			
				Subtotal	188,360		Subtotal	21,724
							Total	210,084

* FR = External floating roof
CH = Cone roof, heated
CR = Cone roof, inert gas blanket

Table 4: Controlled hydrocarbon emissions from hypothetical refinery tankage

Source	Annual volume km³	Tank type *	Floating Roof Tank: Secondary seal emission from: Standing storage kg/yr	With-drawal kg/yr	Total kg/yr	Cone Roof Tank: Internal floating cover emission from: Working kg/yr	Breath-ing kg/yr	Total kg/yr
Crude Oil	5,172	FR	5,217	10,269	15,486			
Condensate	357	FR	1,311	241	1,552			
Residue	255	CH				1,700	3,400	5,100
Gasoline Prod.	1,740	FR	2,205	1,605	3,810			
Sales Naphtha	464	FR	232	403	635			
Reformer Feed.	-	CR				-	4,800	4,800
Reformate	943	FR	444	735	1,179			
Light Naphtha	85	FR	804	89	893			
Heavy Cat. Cr. Naphtha	172	FR	185	207	392			
Light Cat. Cr. Naphtha	343	FR	757	310	1,067			
Poly Gasoline	172	FR	453	214	667			
				Subtotal	25,681		Subtotal	9,900
							Total	35,581

* FR = External floating roof (plus secondary seal)
CH = Cone roof heated (plus internal floating deck)
CR = Cone roof (plus internal floating deck)

Table 5 Values of K_s and n, for calculating standing storage emissions from external floating roof tanks

Tank/Seal Type	K_s	n
Welded Tank		
1. Mechanical shoe seal		
a. Primary only	1.2	1.5
b. With shoe-mounted secondary	0.8	1.2
c. With rim-mounted secondary	0.2	1.0
2. Liquid-mounted resilient-filled seal		
a. Primary only	1.1	1.0
b. With weather shield	0.8	0.9
c. With rim-mounted secondary	0.7	0.4
3. Vapour-mounted resilient-filled seal		
a. Primary only	1.2	2.3
b. With weather shield	0.9	2.2
c. With rim-mounted secondary	0.2	2.6
Riveted Tank		
a. Mechanical shoe primary only	1.3	1.5
b. With shoe-mounted secondary	1.4	1.2
c. With rim-mounted secondary	0.2	1.6

Table 6 Values for C_f factor for product storage related to tank condition (values in $m^3/1000\ m^2$)

Product	Shell condition		
	Light rust	Dense rust	Gunite-lined
Crude oil	0.0103	0.051	1.03
All products	0.0026	0.013	0.26

Table 7: Cost-effectiveness of hydrocarbon emission controls on refinery tankage

Source	Base Case Hydrocarbon Emission t/yr	Control Technique	Controlled Hydrocarbon Emission t/yr	Hydrocarbon Emission Reduction t/yr	Total Capital k$US	Annual Operating Costs k$US/yr	Cost-Effectiveness $US/t
Crude oil	88.6	secondary seal	15.5	73.1	400	121.0	1660
Condensate	19.6	secondary seal	1.6	18.3	36	10.9	600
Residue	11.3	internal cover	5.1	6.2	235	71.0	11 450
Gasoline Prod.	34.7	secondary seal	3.8	30.9	106	32.0	1040
Sales Naphtha	3.9	secondary seal	0.7	3.2	30	9.1	2840
Reformer Feed	10.5	internal cover	4.8	5.7	93	28.1	4930
Reformate	7.4	secondary seal	1.2	6.2	36	11.9	1920
Light Naphtha	12.2	secondary seal	0.9	11.3	24	7.3	650
Hvy Cat. Cr. Naphtha	3.0	secondary seal	0.4	2.6	24	7.3	2800
Lgt Cat. Cr. Naphtha	11.7	secondary seal	1.0	10.7	30	9.1	850
Poly Gasoline	7.0	secondary seal	0.7	6.3	24	7.3	1160
				174.5		315.0	

Table 8

Table 8: Estimate of fugitive emissions from hypothetical refinery

	VALVES			PUMP SEALS		COMPRESSOR SEALS					
	Gas-Vapour Stream	Light Liquid/Two Phase Stream	Heavy Liquid Stream	Light Liquid Streams	Heavy Liquid Streams	Hydro-carbon Service	H_2 Service	Drains	Relief Valves	Flanges	Total
Number of Components: A											
Atmospheric Distillation No. 1	90	281	522	15	28	2	0	69	6	3540	
Atmospheric Distillation No. 2	90	281	522	15	28	2	0	69	6	3540	
Fuel Gas/Light Ends No. 1	88	77	16	4	0	4	0	11	6	760	
Fuel Gas/Light Ends No. 2	88	77	16	4	0	4	0	11	6	760	
Naphtha Hydrotreater No. 1	335	208	102	9	5	0	6	24	6	2600	
Naphtha Hydrotreater No. 2	335	208	102	9	5	0	6	24	6	2600	
Vacuum Distillation	55	50	345	2	19	0	0	35	6	2000	
Fluid Cat Cracker	384	409	521	18	24	6	0	65	6	5200	
Reformer	260	388	43	18	2	0	6	49	6	2760	
Gas Oil Hydrofiner	335	208	102	9	5	0	6	24	6	2600	
Thermal Cracker C	90	281	522	15	28	2	0	69	6	3540	
Poly Gasoline Unit D	200	200	50	10	6	0	0	20	6	2500	
Merox Treatment	60	210	329	11	18	2	0	44	6	2290	
Sulphur Recovery	90	90	20	8	2	0	0	20	4	800	
Total	2500	2968	3212	147	170	22	24	534	82	35490	45149 9659 ex. flanges.
Average Emission/Component, B lb/h	0.059	0.024	0.0005	0.25	0.046	1.4	0.11	0.070	0.19	0.00056	
Total Emission, lb/h	147.5	71.2	1.6	36.7	7.8	30.8	2.6	37.4	15.6	19.9	371.1 or 1474 t/yr or 0.03wt% of crude throughput

NOTES:

A. Number of components taken from Tables 5.16 and 5.17 of Radian Corp. study for EPA, (9)

B. Average emission/components taken from Table 5.6 of Radian Corp. study for EPA (9)

C. Not in Radian study, assume equivalent to atmospheric distillation

D. Estimate; no assessment available

Table 9

Table 9 Hydrocarbon emissions and the cost-effectiveness of controls at the hypothetical 100 kBbl/CD refinery

Source of Emissions at Refinery	Annual Throughput km^3/yr	Uncontrolled Hydrocarbon Emission t/yr	Hydrocarbon Emission Control Technique	I Hydrocarbon Recovered t/yr	I Total Investment k$US	Annual Operating Cost k$US/yr	I,J Cost-Effectiveness $US/t
Tankage							
Crude	5172	88	Rim-mounted secondary seal	73	400	121	1650
Other Feedstocks							
Condensate	357	20	Rim-mounted secondary seal	18	36	11	600
Residue	255	11	Internal floating cover	6	235	71	11450
Gasoline Product	1741	35	Rim-mounted secondary seal	31	106	32	1030
Sales Naphtha	464	4	Rim-mounted secondary seal	3	30	9	2840
Reformer Feed	-	10	Internal floating cover	6	93	28	4930
Gasoline Blendstocks							
Reformate	943	7	Rim-mounted secondary seal	6	36	12	1920
Light Naphtha	85	12	Rim-mounted secondary seal	11	24	7	650
HCN	172	3	Rim-mounted secondary seal	3	24	7	2800
LCN	343	12	Rim-mounted secondary seal	11	30	9	850
Poly gasoline	172	7	Rim-mounted secondary seal	6	24	7	1160
Gasoline Loading:							
Ship/Ocean Barge	400	82	Vapour recovery unit	73	1511	468	6450
Barge (Inland)	160	50	Vapour recovery unit	44	1220	378	8510
Rail	160	59	Vapour recovery unit	52	623	196	3760
Road	521	172	Vapour recovery unit	153	751	239	1560 K
Waste Water Treatment	-	200	Floating cover	180[D]	275	83	460
Fugitive Losses	-	1250[E]	Maintenance & Monitoring Programme	750[F]	0	75	100
Naphtha Loading:							
Rail	46	6[H]	None	-	-	-	-
Ship/Barge	186	22[G]	None	-	-	-	-
Sub-Total	-	2050		1425	5418	1728	-
Ballasting Crude Tankers	-	1500[A]	Segregated ballast tanks	1500[B]	-	-	-
Total	-	3550		-	-	-	

Notes:
A. From the 75% of crude tankers not presently equipped with segregated ballast tanks. Assumes crude oil washing of tanks prior to loading ballast and 30% ballast.
B. Assumes all crude tankers will have segregated ballast within about 10 years under MARPOL agreement.
D. Assumes covers are 90% efficient.
E. Assumes average fugitive emissions of 0.025 wt% on refinery throughput of 5000 kt/yr.
F. Assumes average fugitive emissions with Monitoring & Maintenance programme is 0.01 wt% of refinery throughput of 5000 kt/yr.
G. Assumes loss is 1 lb/1000 gal or 0.017 wt% of quantity loaded.
H. Assumes loss is 0.02 vol % of volume loaded.
I. Data for tankage taken from Table 7, but rounded off, i.e. cost-effectiveness cannot be correctly determined from above t/yr and k$US/yr
J. Cost-effectiveness figures are for ranking purposes only and not for economic justification.
K. Assumes no recovery of vapour return from service station. Becomes 1000 $US/t if this is included.

Table 10

Table 10 Hydrocarbon emissions and the cost-effectiveness of controls at gasoline marketing installations and service stations
(For the 1,740,000 m^3/yr distribution network associated with the hypothetical 100 kBbl/CD refinery)

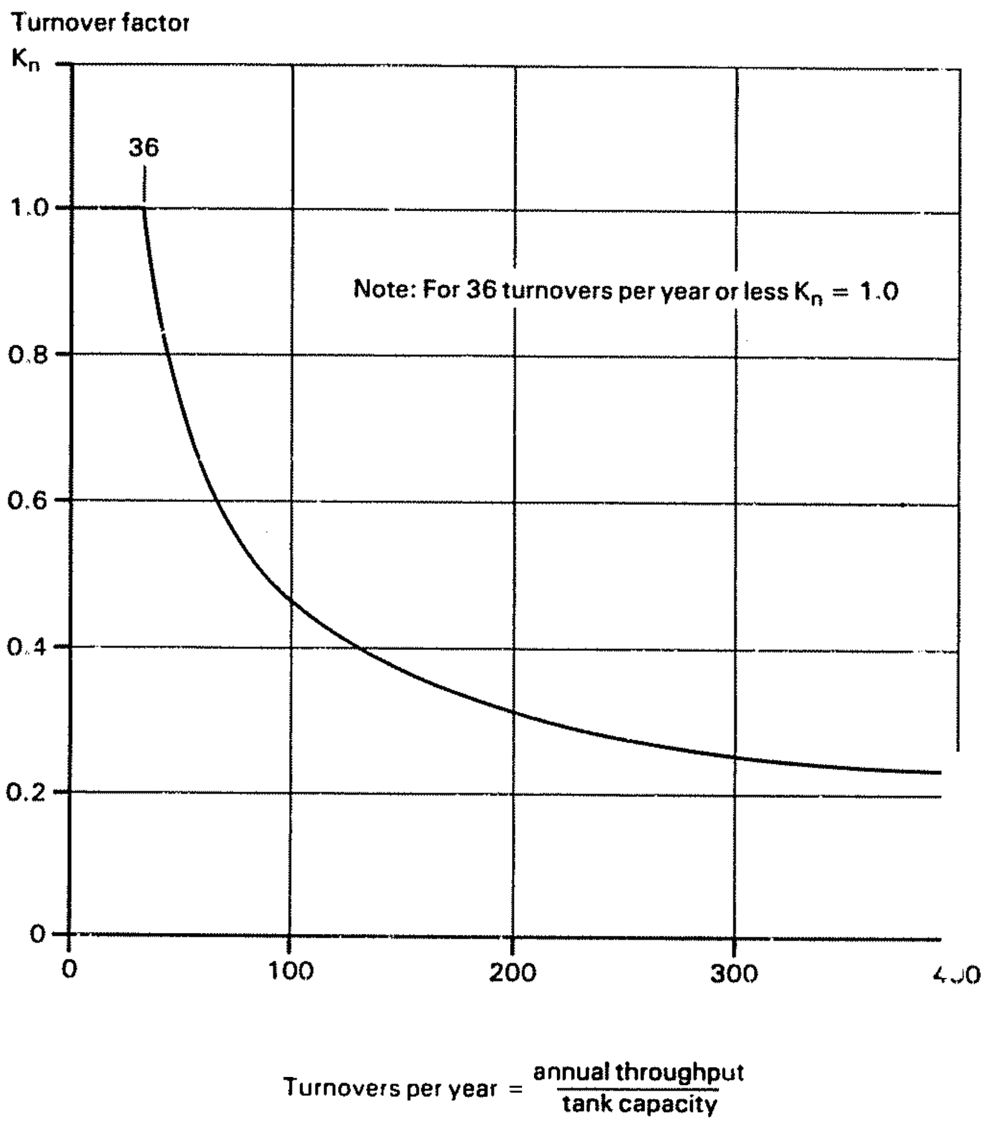
Source of Emission	Throughput m^3/yr	Uncontrolled Hydrocarbon Emission t/yr	Hydrocarbon Emission Control Technique	Hydrocarbon Recovered t/yr (1)	Total Investment k$US	Annual Operating Cost k$US/yr	Cost Effectiveness (2) $US/t
Marketing Installations							
One Large							
Gasoline Tanks (EFR)	500,000	27	Rim-mounted secondary seal	25	85	26	1060
Road Loading	500,000	150 (+480)	VRU incl. return & recovery of service station vapours	617	2002	620	1000
Two Medium (2x200 km^3/yr)							
Ballasting Tankers	400,000	19	VRU	18	-	140	7500
Gasoline Tanks (IFR)	400,000	48	-	-	-	-	-
Road Loading	400,000	132 (+384)	VRU incl. return & recovery of service station vapours	502	2066(2x1033)	644(2x322)	1280
Four Small (4x80km^3/yr)							
Gasoline Tanks (CR)	320,000	365	Vapour balancing lines	Included in Next Line			
Road Loading	320,000	106 (+307)	VRU, incl. return & recovery of service stn. vapours & balancing lines between tanks	766	3064(4x766)	964(4x241)	1260
Fugitive	1,220,000	7	-	-	-	-	-
Spillage	1,220,000	88	-	-	-	-	-
Transport to Service Stns.	1,740,000	10	-	-	-	-	-
Service Stations (1450x1200m^3/yr)							
Tanks	1,740,000	1671	Return vapours to installation	Included above under Marketing Instns.			
Spillage	1,740,000	125	-	-	-	-	
Car Refuelling	1,740,000	1880	Balanced vapour recovery system, "Stage 2" (3)	1691	24475	8500	5030 (3)
Total	1,740,000	4628	-	3619	31692	10,894	-

1) Density of recovered gasoline is 600 kg/m^3.

2) Cost-effectiveness figures are only for ranking purposes and not for economic justification.

3) Onboard carbon canisters believed to be significantly more cost-effective.

Fig. 1 Values for factor K_n, which are related to the number of turnovers per year



Source: API Bulletin 2517 (6) Figure 11.

Fig. 2: Effect of controls on emissions of volatile organic compounds from Western European refineries and product distribution systems and their cumulative cost